FEDERAL ENERGY REGULATORY COMMISSION

WESTERN ENERGY INFRASTRUCTURE CONFERENCE

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P R O C E E D I N G S:

(Welcoming remarks by Chairman Wood)

COMMISSIONER BROWNELL: Thank you.

On behalf Senator Allard, I want to welcome you to Colorado, number one, and also to extend the senator's appreciation to the Commission for being out here to listen to all of the conversation and discussions this afternoon. This is a wonderful way to help the process.

I really look forward to listening to the discussions this afternoon for my benefit and the senator.

Thank you.

CHAIRMAN WOOD: Before I turn it back over to Rick, I would like to acknowledge a number of commissioners from the FERC and also state authorities and other regulatory commissions that we are glad to have here today.

Do you want to kind of say for the ground rules, as you may remember from when we had this in Seattle the last time, please feel free to pipe in with comments or questions. We want this as interactive as possible.

We have this as a different type of issue. This is laying down long-term understandings, developing facts, learning and understanding from a common set of issues and challenges that both we at the federal level can do and that states, utilities -- (inaudible).

We are really just using the ability we have to convene a conference and get a nice turnout here.

Also, to invite again ongoing back and forth participation throughout the afternoon.

We aren't having a real formal break in here, so for any much you all here and certainly you folks singing for your supper, if you all can manage to stay up here.

But if you need to use the restroom or step outside, feel free to do so. We are not going to take a formal break, due to the fact that we have a full four hour schedule here.

With that, I would like to turn it back over to my colleague --

Do you have anything to add?

COMMISSIONER BROWNELL: Just that I'm happy to be here.

MR. MILES: Thank you, Mr. Chairman.

For those of you who didn't pick up a copy of the packet, this include the agenda as well as some of the prepared material Jeff and Todd will present in a few minutes.

Also, when I present the each panel member, I won't go through the resume. You will find at the back of the packet is a resume for each speaker.

When the panel presentations are made at the end -- each speaker has been asked to keep it to five minutes. At the end, we hope to have an interactive session between the panelists, between the decision-makers on both the federal and state sides. So if you have any presentation you would like to give me, please do and we will proceed.

Also, this is a recorded session. We have a court reporter up to my left and your right. He will be taking the record of this proceeding.

With those preliminary observations, let's begin.

MR. WRIGHT: Thank you. I am Jeff Wright, from FERC's Office of Energy Projects. And I would like to welcome you to the energy conference.

The purpose of my presentation is to give a snapshot view of the current electric and gas situation and infrastructure in the west.

For the purposes of the presentation the west consists of the 11 states seen here.

We also consider the contributions of the states and provinces of Alberta, British Columbia and northern Mexico.

The FERC region located in the west is the western electric Coordinating Counsel, WEEC, has four subregions, Northwest PP, Arizona-New Mexico-Southern Nevada, and Rocky Mountain power area and California.

From January 2000 to May, 2003, the west increased its electric generation by 15 percent to 165,400 megawatts.

In the west natural gas and hydro are the dominant fuel sources for generation.

35 percent of the total generation is gas-fired, followed closely by hydro at 32 percent. Coal-fired generation makes up 21 percent capacity and nuclear 6 percent.

The desert southwest has grown since 2000. 39 percent of the subregions capacity is fueled by natural gas and 34 percent is coal-fired.

California has the most capacity. Over half of California's generation capacity is gas-fired.

In the northwest, hydro fuels 60 percent of the generation and coal fuels 22 percent. The northwest had the slowest growth rate at 7 percent.

And although the Rocky Mountain subregion has only 8 percent of the region's total generation capacity, it grew 21 percent since 2000.

Coal fuels over half the generation capacity in this region and gas-fired generation accounts for 27 percent of its capacity.

Here we are looking at the trends in the four subregions in the west. From 2000 until May of this year, almost 21,000 megawatts of generation capacity had been added. Almost all knew capacity is gas-fired.

16,700 megawatts of capacity is expected to come on line between now and the year 2005.

California and the desert southwest have the largest amounts of additions. However, additions will drop sharply after 2003.

Below the zero line are retirements. In the next couple of years, over 3,000 megawatts of retirements will be in the California/New Mexico subregion.

The fuel mix in the west from 1995 to 2005 showed little growth in hydro and coal and nuclear generation capacity.

In 1995 hydro accounted for 42 percent of electric generation capacity.

By 2005 natural gas will fuel 37 percent of the west's electric generation, while hydro drops to 32 percent.

This slide compares the net generation output in 2000 to 2002. That has decreased six percent.

Generation in the California New Mexico area and northwest subregions decreased by 11 and 7 percent respectively.

Generation output increased slightly in the other two regions.

On this slide the map on the right shows the location of hydro power plants in the west.

The table on the left shows how much of the generation capacity in each western state is hydro based.

Hydro power makes up over 80 percent of the capacity in Washington, Oregon and Idaho.

Since hydroelectric generation varies

seasonally, drought can reduce capacity by 25 to 30 percent.

And during the summer months, available energy from hydroelectric facilities can be approximately 50 percent of capacity.

This chart compares energy consumption in the northwest with electric exports in California.

The upward trend, solid red line, indicates increases in energy demand in the northwest.

The downward trend, solid blue line, shows a correlating decrease in the amount of power available for export to California.

This implies as power is available for export from the northwest to California decreases, California must build more generation or become increasingly dependent on the desert southwest for inputs.

I will touch on coal.

Coal-fired generation comprises 21 percent of total capacity in the west.

More than 75 percent of the output from the five states is listed on the slide.

Wyoming is the biggest coal producing

state in the nation, accounting for about a third of total production in the year 2002.

Over 70 percent of western coal is exported to the midwest and southeast.

Driven by incentives to reduce pollution, demand has increased almost 30 percent since 1995.

Non-hydro-renewables consist of mostly wind, geothermal, wood and solar. This category comprises five percent of the total generation mix in the west.

From the map, you can see the renewables are concentrated in California, Washington and Oregon.

The various non-hydro-renewables, wind power. Due to tax subsidies, major improvements in turbine technology and public support, wind power generation has more than doubled since 1990 in the west.

This slide takes a look at the utilization of several major electric transmission paths in the west.

The orange squares indicate 75 percent of the OTC more than 50 percent of the time in the summer of 1999 to 2001.

The location of the heavily utilized paths indicates the west continues to rely (inaudible).

Patterns have changed over time. With the addition of new generation it can be expected the pattern will continue to change.

Several electric transmission projects are scheduled to be completed in 2003. These projects are aimed at localized needs and won't help to relieve congestion in the west.

Western subregions continue to depend heavily on cross-regional flows and will have very few projects to help them between the subregions.

Turning to natural gas, in 1991 electric generation represented 19 percent of natural gas consumed in the west.

It trailed the residential and industrial sectors in their consumption.

By 2001 electric generation represented 37 percent of natural gas consumed in the west, greater than any other consuming sector.

In California uses more gas for electric generation than any other state in the west.

This map shows planned gas-fired electric plants which are 95 percent of total new generation in the west, located along major interstate natural gas pipelines and along intrastate natural gas pipelines in California.

Between now and the end of 2005 a total of 16,700 proposed electric generation is expected to come on line.

Depending on the heat rate, the amount of natural gas needed to serve these facilities could be in the range of 1.3 to 1.6 billion cubic feet per day.

The majority of the generation will be located in the desert southwest and California, with the desert southwest projected to have the largest increase in new generation capacity.

This table provides a comparison of natural gas consumption, production, reserves, storage, imports and exports in the west with the total U.S. for 2001.

Looking closer at storage, California and Montana account for almost one Tcf of the total 1.3 Tcf of storage capacity in the west.

Currently, the storage situation in the west is better than the rest of the U.S. In recent weeks, storage levels in the west were close to the five-year average.

In California, projections remain behind last year's output at this time, but ahead of 2001 levels.

There is a major expansion of existing storage facilities in California that is nearing completion and will increase capacity from 200,000 Mcf per day to 320,000.

California anticipates requiring more storage capacity both inside and outside of the state to meet its future requirements.

Also, these storage facilities have been contemplated in Arizona.

The Commission has scheduled a storage conference to discuss these issues on August 26 in Phoenix, Arizona.

Since reaching a high of 1.3 Tcf in 1998, Canadian exports to the west have declined each year since 2001, which recorded slightly less than 1.2 Tcf.

While Canadian exports declined, imports from Mexico increased from 4 Tcf in 1997 to 31 Tcf in 2001.

These import and export trends continued through the year 2002.

There are 17 major pipelines that traverse the west. The west is dependent on natural gas deliveries from Canada and Texas and natural gas produced in the west, particularly the Rocky Mountain region. (Inaudible).

The west will become more dependent on natural gas supplies produced in the Rocky Mountain region.

However, the west will be competing with markets east of the Rockies. There are projects being proposed to use Rocky Mountain natural gas in an eastward direction.

Thanks to 28 pipeline expansion projects certificated since 2001, pipeline deliverability in the west increased by 6.5 Tcf per day. 3.6 Tcf were intended for electric generation.

And of these 28 projects, 15 added 3.4 Tcf per day of new capacity in the Rockies and ten of the 15 added 2.8.

Five projects are pending before the Commission with a projected capacity of close to 1 Tcf per day.

The largest of these projects, the Cheyenne Plains project, will add 560,000 per day of new capacity and move gas eastward out of the Rockies.

Thirteen projects are on the horizon with a potential capacity of 7.Tcf per day. Nine of these have a potential to move 4.2 Tcf out of the Rockies.

The largest project on the board is the Inland project with a capacity of one Tcf per day, which will transport gas from Wyoming directly to Chicago.

Currently there are eight potential LNG import terminals in the west. Mitsubishi's project, number 6, has been granted the commissions prefiling process.

It's unlikely all these projects will be constructed. However, the construction of any LNG import to California, any import terminal on the west coast contributes substantially to California's future gas supplies and would alter the existing gas flow dynamics in the west by allowing displacement of gas now delivered to California to other western markets.

In conclusion, generation after 2003 will not keep up with California's demand. New California based generation and programs could help meet future loads.

The northwest, Rockies and desert

southwest appear to have adequate power resources for the near future.

Electric capacity increases in these regions could help meet future California shortages as transition lines are upgraded. Still, significant weaknesses remain requiring major backbone transmission for long-term needs.

However, any reliance on power from the northwest is dependent on year to year hydro generations.

New generation is almost totally gas-fired. Diversification could help ensure available capacity due to natural gas or hydro shortages.

The west is dependent on gas production from the Rockies, southwest and Canada. Rockies production should become the dominant source of supply (inaudible).

Also, LNG will be the source of natural gas to California.

Natural gas capacity does appear adequate to serve the regions' demands at this time. However, demand will have to be met by increased capacity.

Storage should be increased to meet peak demands power generation loads will require. Pipeline projects are anticipated to be filed in the near future to serve the demand.

But the question remains whether the capacity will be available in time to meet the demand.

That concludes my overview. Next, Todd Filsinger will be presenting his energy outlook for the west.

MR. FILSINGER: Good afternoon, everybody. I am Todd Filsinger.

I apologize for the logo being upside down. But that is PA Consulting Group. Sometimes we get things backwards.

For those of you who don't know us, we are a firm that originated with PHP in the States. PA Consulting of U.K. acquired PA two years ago.

I am head of the wholesale energy markets global practice. We are involved in primarily all the restructuring and bankruptcy cases across the United States with the merchant generators who have gotten into problems.

And so as I go through the discussion, I will definitely be focusing on its effects throughout the markets.

I should also say that you want to be careful when you walk out of the room because there will be one spot where there will be a quiz.

I first want to talk about the current market conditions. I want to give you a global view of the issues that need to be taken into account with forecasting and how that compares across the different parts of the country and why it's different in the west.

Let's talk first a little about the current market conditions in the States.

Generally, as you look at the industry, it's clearly in a very distressed state. As you look at the assets, both in the west, across all the way to the East Coast, you have a lot of assets that are on the market.

We can name some on the west coast and throughout the west.

Also a lot of the companies are trying to fix the balance sheet. So it's very difficult to sell the projects at full value in today's market.

You are seeing a lot of momentum towards fixing the balance sheet and selling assets in the short-term from the major players.

Well, it's always important, we want to look forward, but it's important to look in the rearview mirror and say how did we get here, how did it happen so fast?

I want to just spend a few minutes on this and talk about the additions. And I think Jeff did a good job of bringing a lot of this up.

If you look at this back in 2000 when the sector was quite strong, we were in a deficit or solid position across a lot of markets and merchants were starting to build facilities.

If you look at the candy striped line in the red, what this line shows you is that across the U.S., the incremental generation that was being announced to be built on a cumulative basis.

So for example, the red line in the year 2000, there were a hundred thousand megawatts of announced generation to be built in the United States and come on line in 2002. Then another hundred by 2003. You can see it's quite dramatic.

But more importantly, as you look at the blue line in 2001 the announcements for the same period of time went up 50,000 megawatts.

In one year's time the announcements for 2002 increased significantly.

Now, as you go to 2002 and a lot of the negative momentum started coming in. You see a little bit of a drop off. But most of it is just pushed off in time.

Now, when you get to the current forecast, you see it's dropped some on announcements.

Again, I want to focus, these are announced facilities, not facilities that will hit the ground.

Let's look at what happened, a lot of these facilities dropped and got pushed out of the way in the back of the forecast.

The source of this information is a PA database of all the facilities in the United States tracked on a weekly, monthly and bimonthly basis depending on the activity.

But you can see how momentum shifted up, then pulled back some.

Now what does that mean across the U.S., particularly in the west?

What I want to show you here is announcements, as you think of announcements, there are a lot of them of power plants, two or three in the same location. You literally would have to build them on top of each other, which is clearly not the way it works.

There is a lot of momentum on Wall Street for the merchants to announce generation, equities continue to go up.

It was only until most recently did Wall Street start recognizing cancellations as a positive versus announcements.

Let's look at the U.S., then focus on the west. If you look across this map, what it shows is from the previous slide, it shows you the announcements versus what I believe will get built in these various regions, and then what is needed in the regions.

If you look at the yellow bar, let's focus on the northwest for a moment. There are 23,000 megawatts of announced additions in the northwest market.

PA's belief that what is needed in the northwest is closer to a thousand megawatts. This is between now and 2005.

This takes into account all the imports, exports in the different regions. And it is based on modeling, so when we get down to each individual state, you will see a little different impact.

As you look at the southeastern part of the country, you see a lot of momentum and announcements, and a lot of units still coming on line.

Look at the southeast, for example, in the lower right-hand corner. In the southeast you have 73,000 megawatts announced of which we believe one-third will come to fruition by 2005.

Only three megawatts, three thousand megawatts are needed.

Now, if we switch to the west, we have in the whole WECC, which Jeff defined. We have 87,000 megawatts of announced generation that has been announced through the end of 2005.

However, PA believes only 20,000 megawatts will come on line, of which closer to 3,000 are needed.

So a substantial surplus in the west and across the United States.

Now, as we look across this, I will get into this more, the west is the most uncertain region, however, across this map.

If we go back to the southeast or Texas or the northeast, when you have those, it's pretty solid. You are going to have that overbuild.

In the west that is not the case. As Jeff brought up, you have a significant amount of hydroelectric which significantly impacts what happens. If you have a low hydro year; the situation changes dramatically.

I want you to keep that in mind as we continue.

Again, what I mentioned was now the big news is, what is not going forward as far as generating plants.

What this shows where the momentum has been across the U.S. as compared to the west, as a lot is being canceled.

If you look at the west, you have 19,000 megawatts put on hold. 22,000 megawatts have been canceled.

Now, these are cancellations in projects put on hold of the announcements. The reason I say that is, if you looked at these, the 22,000 megawatts that have been canceled, of that, probably 1 to 2 percent were actually in my base case before they were canceled.

In other words, they were never going to come to fruition anyway. That is something to keep in mind.

As you look at the momentum, you see quite a few of those in the west are in the California region, and part of that is due to regulatory issues.

But again, the biggest focus of those cancellations really is more in the east.

Now let's talk a little about the oversupply and what its effects are on the actual forecast in pricing.

Again, this is just to give you an order of magnitude.

Yes?

MS. SMITH: Are you going to tell us how you forecasted, (inaudible) based your need on?

MR. FILSINGER: Yes, I will address that. To answer one piece of your question, what I am focusing on now is really the power plants, again, a database of power plants and where they are at.

And to decide what is actually going to hit the ground by 2005 we have two requirements. One, it's either in construction or maintained financing through the banking community or through the balance sheet.

This gives you an idea of the order of magnitude across the different regions. Clearly, as you have oversupply, this depresses prices in the medium term.

This shows and order of magnitude for the different regions as compared to what is needed.

There are two key pieces on this graph that are important. First, the purple bar shows the maximum reserve margin reached, or what I would call the bottom of the cycle, when the market hits the bottom.

For example, in the northwest it's our belief the northwest bottoms out this year. So you begin seeing recoveries this year.

The second bar, green bar, shows when PA believes that region will reach equilibrium, okay. We all know markets don't stay in equilibrium. But that is the point of the crossover.

In the northwest we show recovery by 2006. With hydro generation that crossover point could come much earlier and shift year to year, depending on hydroelectric generation.

If you look in the west particularly, the Arizona and New Mexico region, it's probably one of the more unique regions because it gets, it doesn't bottom out in our view until next year due to some of the large plants coming on line.

It has transmission constraints getting into California. A lot of those plants were built in anticipation of getting into California.

You see dramatic depression in 2004, but a pretty quick recovery due to load growth. And I'll show you a graphic that depicts that.

As we look at this in answer to Ms. Smith's question, on the load to demand size, we look at demand and, again, keep in mind, we are doing this for the lending community and on the restructuring and trying to base it on what I would call consensus forecast.

As we look at the load growth, for example, we relying on the ERI forecasts. We look to sensitivity both on the load forecast as well as generation coming into the marketplace. I will show you what those forecasts are in a moment.

As you look across the U.S. you see how the west compares to the rest of the U.S., not as over built as the rest of the regions.

What I tried to do is summarize that into what I would call somewhat of a weather map. As to the severity of the overbuild, if you look at this continuum, the gray is Florida, it's basically not over built.

As you get into that dark red, that is severe overbuild.

If you look at the over built parts of the country, you are really in the southeast region, then the main region.

As you get in the west you get less of an overbuild.

There are a lot of other things that impact forecast into these particular regions. This gives you a feel for the degree of overbuild.

As you look at the demand forecast, again, this is from the EIA forecast, as you look at demand from the west as compared to the rest of the country, you can see more vigorous projected demand growth which impacts the level and timing of the overbuild. Okay.

Again, we look at sensitivities to the demand growth. But the real issue, what drives these forecasts much more than demand growth, is the level of merchant generation that came in.

For example, if you go back three years from today and look at a forecast. And that forecast was much higher than today.

What drove that more than demand was the amount of merchant capacity that came into the market.

In the west that is a little unique, because demand did get more depressed than a lot of other portions of the country and did extend that some.

So as we look at the overbuild in California and western regions, part of that is due to the decline in demand.

But again, the actual merchant generation came in in anticipation of that load growth, that is really the big driver.

Now, I said remember, hydro conditions in the west can have a significant impact on reserve margins on a year to year basis.

And California tells the story quite well over the last several years.

I just want to demonstrate this with a few dispatch curves to the regions.

If you look at the northwest it shows very well.

As you look at the dispatch curve, what you have on the X axis is megawatts. What you have on the Y axis is dispatch cost.

You can see for almost half of the dispatch curve in the northwest, hydroelectric generation which is close to zero dispatch cost. So hydro conditions are low, you start shrinking that.

The blue line in the middle is average demand, red line is peak. If you shrink that hydro capacity, it doesn't take long before you are in a dire situation in both the northwest and California due to imports of hydro power.

Now, another issue and another big driver of the forecast is gas. The biggest impact, again, is really merchant generation coming into play.

As we do, just a quick summary on that, as we look at the forecasts for Moody's and S&P, a key driver in sensitivity is merchant generation, even though we feel the base case is pretty column vent at this point given the maturity of the market.

As we look at the generation mix of the west versus the rest of the U.S., in the northeast what you have is, the three to focus on, dark blue is coal, yellow is gas, the baby blue is hydro.

As you look at the eastern part of the country, you see significant amounts of coal. You also see significant amounts of coal in Colorado and Wyoming.

But if you look at Arizona, New Mexico and California and the northwest, you are primarily dominated by natural gas and hydro.

So what does this mean? Well, the real issue is not how much generation there is, but what fuel is on the margin in these particular regions.

This map really tells the story of the differentiation between the west, the midwest and eastern part of the country.

Again, if you go to the east you see a lot of blue, which is the coal. This is the number of hours, percent of hours this fuel was on the margin.

As we look at the west we have got natural gas as the marginal fuel in pricing close to a hundred percent of the time in all these regions, much like it is in Texas and southwest power pool.

What does this mean? In your forecast, as you look at the infrastructure for natural gas, it's imperative because it flows through to electricity prices because it is the marginal price setting unit.

If you get a high hydro situation, you would see hydro units potentially on the margin in some cases or pushing up base load, coal and others on the margin, depending on the level of hydrogeneration in the regions.

This is important, as you have combined cycles in this part of the country you will see less projects in this part of the country because you have gas-on-gas competition.

As you go east, you are seeing a lot problem in the cycle in the southeast and east because they compete with coal.

I put a few graphs, and I think Jeff covered this pretty will.

As you look at the natural gas prices, you can see that you had a long-term mean reverting average of probably around 2.20, on a real basis.

As you looked at financing generation and rating these different utilities, they were looking at gas at around 2.07 to 2.20 on a real dollar basis.

You can see here, though, in 2000, 2003, we have seen significant spikes lifting the average.

It's even more apparent in a shorter time frame. We are seeing gas prices moving away from that mean.

There are a lot of opinions as to where natural gas prices will end up. We try to use a consensus forecast in looking at this of the major forecasters. And on a long-term basis, we look at somewhere around 3 to 3.50 long-term in real 2003 dollars.

We also look at significant sensitivities to that based on (inaudible) which are obviously significant live above that.

And that does have different impacts by region.

But I will focus on what that means for the west in a few moments.

I think the transition is, it's obviously, in the west, it's probably a bigger issue there than the rest of the country.

As you look at other regions and self-contained power pools, it isn't as much an issue as for the west.

Basically, the message I am trying to deliver here without getting into too much technical detail is when you look at the different flows across the regions, as we look at each of the particular paths, they are mostly constrained, particularly going into California, almost, most of them between 70 and 90 percent of the time. Significant constraints.

When you look at the Denver area, for example, constraints into the Denver area, all the critical load areas have significant constraints.

This table shows each one of those pieces and the level of constraints.

Well, what does this mean for the forecast in the region? Here I only focused on the west. What I have done, as you look at the forecast, what is going to be important is as you look at this and look at the plants coming on line, how many will come on line, will some be canceled in midstream, or will they all come to fruition.

That is really the important driver in the forecast.

What I have shown here, if we are looking for troubled projects that may come out of the mix, let's look at what it costs to cover debt in these regions, and then what I believe the market will provide long-term.

What this graph shows is, the orange line shows you the amount of spread needed to pay debt on a typical combined cycle type facility.

The blue line shows what the market will provide.

If we are looking at a one-off basis in the west, are you going to see many problems projects in the northwest? No. Not on a long basis.

You will see troubled companies which could drive problem projects. California, same issue.

Those of you familiar with California, the La Palomo project, for example, is a troubled project.

But it's not because of the power plant, it's because of National Energy Group and PG bankruptcy.

That project itself has some big benefits. We are operating as the interim asset manager on that project, which is being turned back to the banks.

As you look at New Mexico, Arizona region, however, you see a different phenomena. You can see that -- you are seeing the spread the market is going to provide being less than what the plant needs to survive.

You are already seeing troubled projects here. You may see some projects pulled back here, which will affect the forecast.

This is where the test comes. This is a power plant canceled in midstream. This is a nice 7 FA GE turbine. This will never be finished.

You see the birds there? I want a show of hands. How many think those birds, A or B, vultures or eagles?

How many think they are vultures?

How many think they are eagles.

The story is, the environmentalists did think they were eagles at first. If they were, you could not move the turbine, because they would nest in the turbines.

It turns out, appropriate to this sector now, that those are vultures. And we were able to move the turbines, and that turbine is now in Pensacola, Florida in a storage facility.

As you saw plants in the generating sector financed at let's say 70/30 debt/equity split. Value them today, 50 percent of what they first were worth, you now have no equity.

This plant is going to be turned back to the bank.

What is bringing this altogether and what this means for forecasting in the west? You have significant announcements in the west.

However, keep in mind that only 20,000 of those are anticipated to come on line, almost a fourth of them, although a significant number are needed.

There have been some cancels put on hold, but not as much as some of the other markets.

Reserve margins will be significant. But because of the hydro conditions introducing a lot of uncertainty into the market, you have a lot of gas and hydro.

But the real issue is gas on the margin in a stable hydro year.

As you look at it where you see the troubled projects and real need for transmission is in Arizona and the other markets.

Summarizing, western markets are over built, but not nearly as much as the rest of the country.

Demand growth is forecasted to be greater in the west than the rest of the country.

Hydro conditions have a significant impact. As you see this you shouldn't walk away and be surprised if next year there will be a price block in California. It's very possible.

The western markets are very dependent on gas as you set the price in the peak hours and shoulder hours.

And there are areas of significant congestion. Again, a lot of generation infrastructure built in Arizona to serve California.

With that, I thank you.

MR. MILES: Thank you.

MR. MILES: Before we begin with the first panel, I have been asked to copy into the record comments of the Bay Area Economic Forum dated July 30, 2003. It's a one-page document. Copies of this document are in the back. We made copies.

Let me quickly summarize what it says.

In its fourth major report of California energy marketplace, the Bay Area Economic Forum concluded that electricity supplies will be tighter than previously forecast.

And there is a significant risk of serious supply shortfalls in the near future.

While supplies appear adequate for the summer, within only a few years, about the time it takes to build a new capacity within the state, reserves could fall to levels that threaten another energy shortfall.

In 2006 to 2008, the whole period will be critical. Of new plants announced since 1998, of them, only about 25 percent are likely to be built.

As the Federal Energy Regulatory Commission works to ensure adequate infrastructure in the west, it's important it recognize not only the requirement of new generation, but also the critical nature of existing generation facilities within California and need to create an effective capacity market.

I will ask the reporter to copy that into the record.

(See inserts)

MR. MILES: Now, our first panel, the issue we have asked them to address is can new electric generation meet western demand.

As we talked about this before today, we have asked them to keep the presentations to five minutes.

At the end of that we hope they will interact with each other, as they did on the phone in our conference call.

We will also welcome questions from the chairman and Commissioner Brownell.

With that, I will introduce Rebecca Followill. She is with the Gas and Power Group. She leads the natural gas power and coal sectors of that group.

Doctor, please.

DR. FOLLOWILL: I think my topic today is on economic and financial barriers to generation in the west today.

It may seem a moot point here as everybody (inaudible). Believe it or not, '06 is less than two and a half years away. If we want generation, we need to be building now. I think it's really not that moot a point.

The question I look at is in the, is the model in place to support new infrastructure in the west. If not, what needs to be done to change that.

In order to build new power plants investors need confidence they will earn an adequate return.

Second, they need regulatory and political certainty they won't be second-guessed and that the rules won't change significantly midstream.

Finally, they need assurance counter parties are financially viable and will perform their obligations over the term needed to finance a plant.

On the issue of adequate returns, the debacles in the west over the past three years along with massive overbuild of generation across the United States has investors seriously questioning the whole merchant generator model.

The days of "build it and they will come" are no longer.

Abundant reasonably priced electricity is viewed as a right and not a commodity where profit can be maximized. If a merchant generator is the upside, the downside is not. It's not a great business model.

We turn to the regulated business model where returns are in part tight interest rates which until the last few weeks were at fifty year lows. Utilities are faced with the dilemma: If I invest now, will I be penalized because interest rates are so low?

If you want to ensure adequate supply, companies must earn a reasonable return and can't be penalized for looking ahead.

On the issue of regulatory and political uncertainty, in my career I can't think of a more uncertain time for people who want new generation from a regulatory standpoint.

While it doesn't sound like an economic or financial barrier, it's the biggest economic risk when you are looking at whether or not you want to build a plant. It should be the first thing an investor evaluates when they want to invest in a plant.

Disasters over the past three years have made regulators understandably cautious to implement new marketing standards and designs.

But as long as the structure remains undefined, people won't want to build plants.

Responding to Jeff's presentation, natural gas is increasingly a key fuel in the west and is increasingly a volatile commodity which makes electricity prices very volatile.

With the volatility, it's probably more important than ever utilities are allowed adequate fuel cost recovery. That they are not unfairly punished by disallowing recovery just because the market is volatile, and that they are allowed to hedge within reason.

We are still in the punch-up phase in California. We need to move through it as quickly as possible.

Every time the market hears about one more marketing certificate being yanked or one more show cause order, they take another step away from building new generation.

On the issue of price caps, even though I must admit they were needed at the time, the signal they send is don't build.

The last issue is counterpart insurance. We don't have it now. That will take time to return and get the market stabilized. The pendulum has come full circle and we are where we were 15 years ago: long-term contracts for power. I think frankly that is where we should be.

To sum it up, to ensure adequate generation the market needs assurance they will earn adequate return, resolution on a variety of regulatory and political issues, and return to mutual cooperation instead of excessive profits, and (inaudible) .

MR. MILES: Thank you.

Our next speaker is Peter Moritzburke, director of the Western Energy Office for the Cambridge Energy Research Associates.

MR. MORITZBURKE: Thank you for the opportunity to address the Federal Energy Regulatory Commission and participants.

At a time when many state and federal electricity policies have been largely reactive, North American power markets are badly in need of proactive policies.

Western markets are over built now, but this is not a permanent condition. Rocky Mountain and California regions will come back into balance by 2008. Most other western regions within a few years after that.

Five years is not long, given lead times required to build many power assets.

In the meantime, local and long distance transmission bottlenecks persist in every region to affect reliability and deter market participation.

In short, the west is out of the woods for now. But there is potentially another forest right ahead of it.

Recent history in the west clearly shows that failure to plan ahead by setting up the right market structures can result in a crisis.

At this time California is in the same position it was in 1996 and still does not have a mechanism to insure that new supplies arrive before shortage occurs.

Similar to that time, spot prices are again too low to stimulate new merchant plant development.

Preventing another crisis in 2008 requires coordinated market reform and development efforts now, but also to reach common goals shared by most participants.

Those goals include adequate operating reserves, supply reliability and diversity, regulatory stability and predictability, financially stable creditworthy market participants and liquid transparent power markets that allow suppliers and load providers to hedge exposure as well as send the right signals regarding future resource needs.

In a few years power development activity in the west will dry up. Not before developers succeed in overbuilding the market.

14,000 megawatts of new mostly gas-fired generation is under construction in the WECC, including western Canada, bringing total through 2005 to 40,000 megawatts.

Capacity being built now will only increase already bulging operating reserve margins.

Even in the event half of all capacity currently under construction is delayed, markets are well supplied through 2006.

The new generation is not evenly distributed across regions, with the southwest becoming one of the most over built in North America.

Stock prices there as a result will fail to allow recovery of initial investments or adequate returns on those investments.

Many policy makers are relieved that near-term reliability is no longer a constant concern, but over built markets are in part a bad thing, because they allow the western regulators and legislators to postpone the task of ironing out market problems that persist.

State regulators may balk at utilities applying for development of capital-intensive non-gas-fired resources when existing merchant-owned gas-fired plants are likely to sell output near short-term marginal costs.

For years to come power prices will reflect the underlying costs of that output with minimal stress.

Even so, in California a state that should understand the risks of future shortages very well, utilities are only able to sign contracts of up to five years in duration.

This is too short to stimulate new capacity construction.

Next graph, please.

In today's half restructured power business, a condition SERA has called the new hybrid, utilities are the main creditworthy participants.

Ownership of assets in the U.S. is shared by merchants who own 43 percent of capacity. Because restructuring efforts have fallen short of a fully deregulated entities, utilities have retained most of the responsibilities for the environment, risk management, for operating and maintaining transmission systems and for determining wholesale capacity and energy crisis.

Our half successful attempt at market restructuring has created a vacuum where, prior to 1997, utilities coordinated supply development.

As a result, the overbuild is nearly exclusively dependent on a single fuel, natural gas.

This dependency comes at a bad time. Following a modest improvement in the gas demand/supply balance, problems will return in 2005 and beyond.

This will translate into higher demand and supply limitations, meaning that that growth will come at the expense of industrial gas demand.

Dependence on gas will make power prices higher and more volatile, since gas-fired generators will be a marginal source of output most of the time.

In order to meet this and other gas demand, SERA foresees the increasing need for more costly frontier gas resources such as LNG and Alaskan gas, supplies that have long project lead times.

So its responsibility for integrated resource planning returns to western utilities. More emphasis will need to be put on generation fuel diversity.

The question then needs to be addressed: How does the west create sustainable competition in stable power markets that attract diverse types of generating capacity in advance of a shortage?

In the near-term the answers lies in the hands of federal and state regulators. Thus, SERA has some recommendations. Five specifically.

The first, adopt an operating reserve target. The Commission's proposal last summer pursued a worthy goal of requiring load serving entities to meet a reserve target or pay real time price penalties.

The details of how that target would be set and met was in part delegated to the states.

SERA favors an operating reserve target or structured path to the markets as the best way to signal future value of capacity and assure it arrives on time.

Two, align wholesale and retail markets. Retail customers exposed to the fluctuating costs of wholesale power will conserve.

Utilities in the southwest have implemented time of use rates and real time meters on a broad scale, with successful results.

Expanding retail choice would allow customers to help determine the amount of renewables or other resources that they want to meet their demand.

Number three, streamline new generation development. Many states need to reduce siting and permitting hurdles. Particularly notorious is California, where in the past it's taken up to seven years to build a new combined cycle gas-fired plant.

In the wake of the crisis, California is working to consolidate the process. But it has much work left to do.

Four, open up opportunities for new transmission development. The Commission has studied ways to break deadlocks over transmission siting and permitting and restructure operations and pricing through RTOs.

Success over time should enable remote generators to access western load centers.

For one clean coal in the Powder River Basin comes to mind.

It will also expand private sector participation in a part of the industry badly in need of investment.

The fifth and last recommendation, encourage non-conventional resources. Greater cooperation between state and federal agencies and the private sector could result in a very different western power landscape.

Aging coal plants are ripe for reinvestment to become clean coal plants or fueled by coal gasification.

On another front renewable and distributed generation are becoming more viable as a means to diverse the resource base as cost and integration barriers drop.

Although they are unlikely to play a large role in growing supply needs, excuse me, growing needed supplies, they will provide capacity over time and can be effective.

In conclusion, the five years needed to bring California and Rocky Mountain power markets back into balance will pass quickly.

Although policy makers are making progress towards fixing western markets, the incentives they provide must be reshaped in critical ways to stimulate appropriate responses in advance of shortages.

Thank you.

MR. MILES: Thank you, Peter.

The next speaker is Jeremy Platt. He is manager of power and fuel markets with Electric Power Research Institute.

MR. PLATT: Thank you very much.

I was invited because my company produced a report that mentioned the word retirements in the title.

We have been tracking new power plants since December 2000, with earlier studies focusing on the building that first manifested itself in New England and Texas.

We assessed the impact of this building on the regional reserve margins in a report issued January 2002, edited February, 2003.

The principle thrust of the latest report was to evaluate the magnitude of requirements on excess capacity.

Other considerations have been development plans, how many plants not yet in construction might actually go to completion and, what if electricity growth rates were higher than lower than in regional projections.

I think I would argue there is less uncertainty about development plans now and put more of the weight on load growth.

The west is a large area. I didn't have exactly the guidelines, so I was looking at about 16 states in the west, not including those bordering the Mississippi or Texas.

Great differences in generation and mixes are seen. Our assessment concluded tentatively as many as 45,000 megawatts of oil, gas and coal generation might be retired between 1998 and 2010, almost 12,000 in the west, including only 640 megawatts of coal capacity.

California is responsible for the biggest portion of these requirements, close to 7,000 megawatts.

More details on the west retirement total. Nearly half are natural gas steam cycle plants. 5800 are number 6 fuel oil.

53 percent of the total projected, almost 4,000 megawatts, have been announced already, scheduled to occur through 2004. Nearly all are gas and nearly all in California.

45 percent of the total of this whole span of 12,000 megawatts, only 5280 are projected to retire but only towards the very end of the period, say 2010. But I wouldn't be too firm about that estimate. Most of those are resid' burning.

The projected retirements from the methodological point of view are judgment calls. We haven't done a detailed financial analysis of the markets and payout of each of those plants.

Consider these things. The age, usually 50 years old or more.

Size, often very small plants, with one exception being the Marrow Bay facility in California.

Efficiency which is lower for all older plants. Many were built in the '40s and '50s.

Environmental performance is affecting the calculus.

Finally, the adequacy of generation, where there was excess of 30 percent, it seems more vulnerable to retirement.

One wild card is this choice between retiring and mothballing. Mothballing cannot be ruled out among the figures cited and with the preferred choice (inaudible).

A second wild card is designation of plants.

On the bottom of the page I show the capacity additions to give some perspective on this.

It's important to take account that maybe between 1998 and 2007, our investigator on this topic out of Arlington, Virginia, has anticipated about 250,000 megawatts of natural gas-fired combustion turbine, combined cycles to be built across the country. About 52,750 megawatts in the west.

Here I am saying 1998 to 2007. This is close to four and a half times the announced projected retirements through 2010.

A further perspective, the next slide, on the generating infrastructure is something similar to what Peter showed.

It's gained from calculating regional reserve margins. Mid-range load growth forecasts and capacity additions. We can see the trajectories of reserve margin appear above 30 percent for these assumptions in most areas through 2010. Load growth is a major uncertainty.

I conclude this comparison between retirements and capacity additions leads me to conclude the issue of power plant retirements is not a controlling business or reliability planning issue and possibly not even in 2006 as we might have heard by the Bay Area forum.

We have seen dramatic changes in outlook from one assessment to the next.

I could reinforce that. I have one more slide. We could show that.

MR. MILES: Yes.

MR. PLATT: Yes. I'm trying to reinforce here a sense of the degree to which I guess not just what gets built is uncertain, but also the degree to which load growth is uncertain.

This particularly comes out in spades in

California.

In November, 2001, there is a set of gray bands out there in the future that reflects the capacity built uncertainty using mid-range load forecast out into the future.

You see by the time the energy crisis had been absorbed and by November, 2001, people had a lot of expectations on new capacity in California.

A year later, there is an orange band near the bottom, and you see a lot of cancellations took place.

We also took into account our retirements analysis. Those modest but real California retirements plus developer cancellations and deferrals led to a different and much lower view of capacity.

As long as we keep the mid-range demand forecasts, it looks like we have gone from happy times to dire straits.

Where we are now is the red band in the middle which emphasizes the supply rate uncertainty.

The two curves with little white dots represent the demand uncertainties around the mid-range of development.

You can see we seem to be out of the woods. The reason is that we got the demand forecasts now that are around 1 1/2 percent, and that a capacity tight point we thought might have happened in 2002 now might not be, appear in California until 2006.

That is the degree to which demand alone and building has made quite an impact on the uncertainty we are projecting.

Thank you.

MR. MILES: Thank you.

Our next speaker is Charles Goldman, leader with the Electricity Markets and Policy Groups, Lawrence Berkeley National Laboratory.

MR. GOLDMAN: Thank you.

As the only one of 16 speakers today who is supposed to talk about the demand side, I hope you will indulge me and give me seven minutes instead of five.

The question posed to the panel today is: Can new electric generation meet western demand?

I would suggest that might be the wrong question. The question may be: What is the appropriate mix of electric generating resources and demand side resources that can produce reliable, affordable, environmentally acceptable power?

How can we use planning and marketing mechanisms to achieve that objective.

I'm not sure people think about the demand side as part of the infrastructure, but I would like to suggest it's something we should consider seriously.

We used to do it. And we will be increasingly be asked to look at it in those terms by customers and other folks out there.

My remarks will focus on several topics. First, demand response defined to include short-term load response, energy efficiency, time-sensitive pricing and generation is a significant untapped resource for western electric markets.

I'm going to highlight some of the historic activities of demand response in western states and summarize recent studies and planning activities that estimate remaining achievable cost effective potential in the west.

I'm also going to discuss some of the policies FERC and the states would have to implement if they want to capture demand resources over the next decade.

And finally, I want to emphasize that because gas is on the margin in the electric sector that accelerating actions now in the west would have the additional benefit of mitigating high gas prices and supply constraints that are a significant threat over the next three to four years.

This chart from the Energy Information Administration summarizes reports given by utilities about their activities in the area of load management and energy efficiency.

You can see from this chart, over the last four or five years we have about 10,000 megawatts of curtailable load reported by utilities in the west. About 25 percent of that amount is called in any one year.

But most of this resource is what I would characterize as legacy load management programs. It's curtailable interruptible rates, load control, and a smattering of sort of next generation demand response programs, quote programs, all option programs.

But the vast majority is the traditional stuff that has been known for the last ten or 15 years.

In addition, there are about 2500 megawatts of peak demand reduction that occurs through energy efficiency programs in addition to all the energy savings they produce and thousands of hours that energy efficiency measures are actually deployed.

This slide summarizes some rather disparate studies done in California, the southwest and northwest by different organizations that take different looks at the cost effective potential for energy in the west.

The first was done by a consulting firm done in part for the California Utilities and Energy Foundation. It estimates an upper bound of about 9500 megawatts of cost effective potential over the next ten years.

The study goes on to talk about what is more of achievable kind of targets based on current funding levels for energy efficiency in California.

We spend about $275 million a year, if funding was doubled, we could produce about 3500 megawatts of peak demand savings, offsetting

35 percent of projected load growth in California over the next ten years.

In the southwest this is a study done by the southwest energy efficiency project. I would characterize this as a very aggressive study in terms of technical economic potential, because this part of the country, these six states Arizona, Denver, Colorado, New Mexico, Utah and Wyoming, have very high load growth, and there hasn't been a lot of energy efficiency study done in this region.

You could cut that load growth substantially if you replicated some of the things that have gone on in California and the northwest the past ten years.

I suggest that this represents a very high upper bound of what you might want to consider for that region.

The third study was done by the Northwest Power Planning Council working closely with BPA.

I would characterize this as a much more conservative approach. They estimate 3200 average megawatts, cost effective potential remake in the year 2020, 2025.

That offsets about 60 percent of demand

growth under their forecast

Next slide.

Now, because the power planning council has been around ten or 15 years, and because they have been pretty much on the mark in terms of actually doing conservation assessment potentials, naturally, it actually occurring in the field, this chart shows where the resources are actually buried. It highlights an end-use approach.

In this study they used a number of around 450 to 600 mils as what you could capture in the regions over the next 20 years.

It's a smattering of residential appliances, lighting, space conditioning and commercial applications.

I suggest this kind of analysis is what has been done in California, done in the southwest. But it's the kind of work you have to do if you want to think about harnessing the demand side.

What needs to be done to better utilize demand response resources? Demand response is really at the nexus of wholesale and resale regulation. Some things can be done by FERC, a lot have to be done by states.

In terms of resource -- I agree with Peter's comment, it's really critical to think about that kind of what you want to do with the area of resource adequacy.

As states and multi-state users develop, their roles and policies, I suggest you consider how they might compete fairly in whatever rules you set up.

It's also important to deploy an expanded metering, hourly systems that enable customers to see time sensitive prices.

In the area of short-term emergency demand response programs, I would suggest a lot of the stuff utilities report to EIA, it's been around a long time, not used very often, not clear it works very well. We learned that in California.

States should begin to set targets for load serving entities in terms of what load they think is appropriate.

I think you should think of that in terms of the cost of that approach versus what peaking capacity might cost.

You need to develop a strategy to transition legacy load demands. Some regions have a lot of experience, in New England and New York, of sort of what that process might look like.

I think the west will have to look at that. You should think about setting payments to reflect value of system reliability to customers pretty explicitly.

In the area of energy efficiency, I think we have learned over the last ten or 15 years resource potential can be most effectively captured through a combination of policies: Appliance efficiency standards, updated building codes, ratepayer funded programs and other policies and strategies states adopt.

In those states that are considering integrated resource planning, again, those planning processes should consider all the source options to meet existing needs and think about them in terms of cost effectiveness.

States should also consider establishing or increasing ratepayer system benefit funds.

You might want to consider looking at energy efficiency performance standards. That is the approach Texas has adopted, where 10 percent of load growth is met by efficiency. An interesting concept, and it seems to be working pretty well.

You need to also address rate-making disincentives to utilities and/or consider other entities to administer EE programs.

Thank you.

MR. MILES: Thank you.

Any comments, reactions, questions? You've heard a lot about reserve margins, five-year versus 15-year contracts.

MR. PLATT: I just got a gas price reduction, which is interesting. The DSM doesn't show up in my bill that would have a high gas price.

It will probably be another eight months or whatever before today's gas market is reflected in local bills.

I would ask Charles to comment on the signals.

MR. GOLDMAN: I just came from the meetings where we were on the Electric and Gas Consumer Affairs Committee. Had several panels on the looming gas crisis in the west. I do think it's clear, the price signal is transmitted rather slowly to some customers.

It was somewhat humbling to see the gas price forecast out there and what they might imply about feedback in terms of the electric market as well as residential gas customers. I think it's -- a lot of commissions are looking at that pretty closely.

MR. MILES: Questions from the audience?

MR. SOPKIN: I would first like to welcome Chairman Wood and Commissioner Brownell. I'm the new chairman of the Public Utilities Commission, I hope you enjoy our beautiful state.

When I think about this issue, one of the panel members talked about having a diverse portfolio of energy resources, which certainly makes sense.

But there are a lot of uncertainties about each element of the mix. Natural gas, there is a huge uncertainty about the future of prices, because we can't predict the weather and because we have significant supply concerns that apparently won't be fixed for several years.

The LNG market is a way, it's five to ten years away. There doesn't seem to be much increase in production at the domestic level.

When I think about coal, we have a very

huge uncertainty, which is whether the federal government is going to start regulating or limiting the amount of CO2. And that certainly affects whether that becomes part of the mix.

You also have significant capital and return issues with coal because of the initial outlay and several years of not earning a return on that.

And then we have wind and the uncertain issue of whether federal subsidies are going to continue with wind.

At least from my own standpoint, it's difficult to measure what the associated costs of wind are, the backup costs, the costs of dispatch and cost of transition, because it really hasn't been tracked and we don't seem to get a lot of independent studies about those sorts of things.

When I look at all this, I guess this is a difficult question, how is a regulator to compare these things on an apples to apples basis, question number one.

Question two, how can the federal government provide more assurance to the states regarding pollution controls and subsidies?

Anybody can take a stab at this.

MS. FOLLOWILL: Don't put all your electric assets into one basket because you don't know what is going to happen, that is why you have a variety of assets, as wouldn't put all your stocks into one basket.

You make your own judgment. Sometimes you are right, sometimes you are wrong.

I have my own opinion, but sometimes I'm right and sometimes I'm wrong, too.

As far as what the federal government can do, the uncertainty on the environmental issues are key. We need to get past what the standards are going to be and resolve it quickly.

So as much as you can to push that forward, you do what you can.

I know a lot of folks are looking at building new coal-fired plants, with the big uncertainties -- (inaudible).

MR. MORITZBURKE: First of all, good luck. It's extremely complicated. I think it in part depends on the appetite of utilities and commissions that regulate the utilities to sign contracts to support the different risks.

Coal generation, with all the appropriate mitigation technologies for current and future regulations, those technologies are available, those costs can be incurred. It just depends how you want to work them back into the rate base.

It is going to require contracts in order to do that. So those contracts are either going to be -- either will come from the Commission level within the states or, if you -- or capacity market, that will signal value of that going forward.

MR. SOPKIN: Thank you.

MR. MILES: Good.

MR. GOLDMAN: I would urge you to think about the apples to apples basis and include the demand side as part of the equation.

I would submit the Pacific northwest has done an excellent job the last 15 years of documenting, thinking about energy efficiency and documenting, evaluating what the resource actually cost toss acquire.

If you decide to put your eggs in that basket, I would urge you to require of your utilities that administer those programs that they do the same, so you can be convinced and other resources out there can be convinced you are getting what you are paying for

MR. PLATT: I think the tremendous response of the industry might mitigate a lot of concern over natural gas and camouflage the disturbing fundamentals.

You are correct in being nervous about over the next several years.

I don't think energy economic planning has really absorbed that or society has absorbed that in terms of what else we are going to do if gas is truly as expensive as it could prove to be and hurt more people than a mere fertilizer industry, for example.

I guess another point I would make is that in any forecast you do look at, you should look very carefully at the capacity factors being considered on the payoff of new generation.

I think that is one of the biggest problems we are seeing right now in the performance of (inaudible) is extremely low capacity factors.

So what might look good at 80, 85 percent comparison of coal to gas looks very different at 35 percent. Just keep yourself pushing on those questions.

MR. SOPKIN: Thank you.

MR. ROWE: Bob Rowe, from the Montana commission.

I also want to join in thanking the FERC for coming out here. This couldn't be a better topic or more timely.

It may be I'm than interloper from the telecommunications industry, but as I hear you and the preceding speakers describe a couple important issues, I hear quite a range of opinions, from gas supply, gas price, what is going to happen on the new generation side, plant retirements, reserve capacity.

Am I correct that there is in fact that kind of substantial disagreement?

If I am, what is the appropriate response? In fact, are we, as Richard indicated and others maybe, stumbling back towards the old IRP model?

DR. FOLLOWILL: I don't think there is that much disagreement. I think it's just the time we come back in balance in a specific region which could be '06, maybe longer.

As far as natural gas goes, I think we are okay for now. But if we get a cold winter, all bets are off. And beyond is the real question of what happens.

I think people are seeing a little breathing room. Gas prices come back below $5, what happens next.

PARTICIPANT: I agree the issue is really in the out years, not the next several years. That is where my question really goes.

MR. MILES: I think we have time --

MR. PLATT: I think we are fully agreed, actually.

First, I don't think we are okay, I think that is pretty high. I think there is some analytical uncertainty around California, the big elephant in the west.

I think it's in the interest of any consumer driven forum to forecast dire conditions through as much capacity building as possible. You have to be aware of vested interests, should they be part of any assessment.

Another issue I think in California is indeed what demand forecast is assumed. I do believe most analyzes have a reasonable agreement over the capacity building now.

I think they agree what is considered and what is not and what might come in. I think more uncertainty is in demand.

Possibly the differences you see in California adequacy is around demand assumptions.

MR. MORITZBURKE: As a footnote to the cost margin discussion, I would agree we are all in general agreement on the general range of degree balancing the California market.

Demand growth is definitely a significant variable. In the past we have seen analysts and generation developers forecast extremely aggressive demand growth trajectories which we don't believe will come to pass.

Another key factor is retirements. When you look at a lot of the gas-fired capacity in the subregions of the west, southwest and California in particular, a lot of that capacity resides within load pockets, so it's required for reliability must run purposes.

We don't see a lot of transmission upgrades in those regions to relieve those constraints.

MR. MILES: Yes?

MR. BAILIS: Thanks. Rich Bailis.

It appears to us one of the biggest barriers out here in the west to facilitate expansion of remote coal and cheaper resources, renewable and wind, is transmission infrastructure financing, especially if it has to be done on a participant basis.

The governor did a study a while back being updated, you will hear from Dean Perry later on that, that shows significant benefits from building more transmission especially across the region.

But the benefits are widely distributed amongst all the states. If it was allocated to just new generators, it would not only create better prices on the margin but reduce congestion for the competitors.

The question is, how can we overcome this financing barrier to new transmission that might allow more generation to be built when we see these multiple state benefits? How can we resolve that, the allocation?

MR. MILES: Any takers?

MR. PLATT: Isn't there a panel that deals with that later?

(Laughter.)

MR. MILES: We can always defer the question until later.

Any comments?

MR. MORITZBURKE: Contracts, again. To the extent utilities and commissions are willing to absorb costs of new transmission development, resources will be there. It just takes contracts.

MR. MILES: Our period for the first panel has ended. I want to thank the panelists for their presentation and hanging in there with the time constraints. On behalf of the Commission we thank you very much.

(Applause).

MR. MILES: Can we have the next panelists? Five minutes.

(Recess.)

MR. MILES: Thank you very much for your cooperation.

As our last panel, we asked the question can the new electric generation meet western demand.

This panel has been asked to address can natural gas meet future energy needs in the west.

So why don't we begin. Same rules.

Mr. Roger Biemans will be our first speaker, president of EnCana U.S.

MR. BIEMANS: Good afternoon, Rick.

Welcome to Denver, everyone.

In addition to my day job with EnCana U.S., I'm also vice president of the Independent Coal Association of Mountain States.

I'm really here on behalf of the entire producing community in the Rockies. I would like to thank the Commission for the opportunity to speak here today.

Our story is about the significant gas supply potential of the west, specifically the Rockies. This region contains the largest on shore reserve potential of natural gas in the U.S.

The federal government, through its vast land holdings, controls approximately 75 percent of this resource and has responsibility to ensure that it is developed and transported to markets in a reliable and timely manner.

Currently natural gas production in the intermountain west is being constrained, causing some bases to decline when they should be increasing production.

This is due to combined effects of bureaucratic delays as well as protests, appeals and lawsuits by groups opposed to development of any forum on federal land.

As a specific example the Powder River coal bed natural gas in the Pinedale fields, all of Wyoming could be producing as much as an additional 3 PCF today. The potential to grow is great, but we must find ways to work together and ensure that this happens.

Whether you look at recent discoveries, production trends, resource potential or reserve growth, everything points to the important role the intermountain west must play to ensure -- in ensuring the United States energy security.

Take the following facts and statistics as evidence of the significance of this region.

Three of the four largest gas discoveries, on shore gas discoveries in the last 25 years have been made here in the Rockies. San Juan Basin, Powder River, both coal bed natural gas and Jonah Pinedale fields.

Natural gas production has increased by more than 500 percent over the last 30 years, while all other regions in the lower 48 have experienced declines.

(Inaudible).

Total gas production has grown from a

mere 9 percent in 1990 to approximately 9 Tcf today.

The basins in Wyoming, Colorado, Utah and New Mexico have an average reserve life index of 14.75 years.

Contrast that to Oklahoma, Texas and Louisiana which have an average reserve life of eight years. It's easy to see why so many are optimistic about the future growth potential for natural gas in the west.

Yet barriers such as delays, the protracted NEPA process and spurious litigation must be addressed if the region is to reach its full potential.

These problems limit the number and ability of pipelines to procure long-term capacity needed to construct or expand pipelines.

I'm sure Brian's presentation will further expound on these factors and the disconnect between energy prices in large consuming regions versus the Rockies.

This disconnect or basis differential is a serious economic deterrent for developing our resources we have here in the Rockies.

Public debate over the natural gas

production on federal lands normally focusing on access, in terms of (inaudible).

Although this is an extremely important issue since nearly 36 percent of the region is off limits today, it's important also to pay attention to delays that occur on land already leased.

A typical environmental impact statement, EIS, required by NEPA, can take up to four years to complete, often containing restrictions that severely restrict access and development.

Additional access delays are encountered during the permitting process. The BLM now takes an average of 175 days to approve a permit to drill a well, a process which its own regulations say should take no more than 30 days.

In just four of 25 field offices, there is a total backlog of 1700 permits. I mention the statistic not to lay blame on the BLM but to point out that such federal agencies desperately need funding, resources, manpower and green light from congress to do their job more efficiently.

Federal statutes which allow for public involvement are misused by obstructionist groups to slow, if not stop development of natural gas with protest and litigation at every stage of energy development.

This misuse of the public involvement process is expensive not only for operators and federal agencies, but more so for the nation in terms of natural gas supply and energy costs.

I look forward to working together to ensure energy demands are met in an environmentally sound and sustainable way.

In closing, we are encouraged by the administration's efforts through the Commission, BLM and White House task force to address energy development in the west.

We recognize there are many issues remaining to be addressed.

Thank you.

MR. MILES: Thank you.

Our next speaker will talk about Rocky Mountain infrastructure needs. Brian Jeffries, vice president for marketing, Western Gas Resources.

MR. JEFFRIES: Thank you. I would like to thank the Commission for the opportunity to present a producer perspective.

I am speaking on behalf of the Independent

Petroleum Association of Mountain States. As producers are not an entirely homogenous lot, I would ask you not attribute any of my comments to any specific member of our group.

Roger has spoken about the enormous productive capability of the Rockies, and Jeff Wright's presentation described the many projects added to the Rocky Mountain region.

However, many of the projects add capacity only within the regional or are part of a sequence of projects that feed one to the other.

(Inaudible)-- total creates an overstated impression of the total export capacity out of the Rockies.

Currently there is excess export capacity out of Wyoming, Utah and northern Colorado, roughly half a Tcf today. All this excess capacity is to the northwest down to the San Juan Basin.

Pipelines to the east of the Rockies are full. On a winter day the excess export capacity rises to approximately a Tcf today as local loads, Denver and Salt Lake absorb supply.

It's important to understand in the Rockies these local loads exert significant impact on the value of export capacity and basis. Projected supply development in the Rockies is more than sufficient to absorb this excess capacity, with capacity in the summer and shoulder months going first.

As supply in the Rockies grows or as local demand in California and specific northwest changes such as it does in response to fluctuating hydroelectric generation availability, congestion will occur, price signals will be sent and discussions of adequate infrastructure will continue.

Adequate infrastructure is, however, an undefined term. I can offer two definitions to help. The first is a price definition.

Infrastructure is adequate for the congestion on the grid, is not affecting prices beyond tolerance level for producers or consumers.

Development is a reactionary process in response to the market conditions. This definition has replaced a reliability definition, that is a definition that all gas that needs to flow can flow somewhere, and all gas that needs to be consumed can come from somewhere.

Prior to deregulation, pricing was not an issue. With respect to the natural gas grid, currently all infrastructure development is done through participant funding.

As export capacity in the Rockies continues to build, individual producers will react to price signals caused by congestion and will fund capacity expansion.

There is widespread agreement that the FERC's certificate staff does a superb job of expeditiously processing applications once filed.

Unfortunately for the Rockies, it's been taking too long to get from a pipeline proposal to a certificate filing.

At least one recently filed application represented a project that went through a five-year trek from its first proposal to reaching a certificate filing stage.

Unfortunately, I have four suggestions for the Commission to consider.

Encourage individual commercial decisions, support potential expansion projects and get those projects to a filing stage sooner.

First, in no particular order, allow shippers and pipelines to share the risks and rewards of the actual market value of expansion capacity through index to index contracts that are subject to caps and floors on the absolute rate.

Floors and caps on absolute rates can address the Commission's concerns over market power of pipelines and shipper indifference to the rate.

Periodic true up calculations based on cumulative revenues can be built into the rates from time to time.

These type agreements would allow a shipper and pipeline to share benefits and risks once constructed capacity is at various times too much or not enough.

Second, the Commission should consider waiving the cap on capacity release rates for at least the initial term of expansion agreements. To the extent a producer has contracted for expansion capacity and can't use it, the current cap of release rates over only the prospect of lesser (inaudible).

Currently, the only mechanism to capture value of capacity that is worth more than its cost is to buy and sell third party gas across the unused capacity.

Not all producers are in a position to take on the additional costs and risks associated with third party marketing.

Third, the Commission should consider granting greater latitude in the application that the shipper must have title.

The state of Colorado has granted Wyoming pipeline authority to be able to take capacity on the pipelines for the purpose of supporting capacity expansions out of Wyoming to move additional gas to market.

One possibility is for the pipeline authority to track capacity and then make the capacity available to a pool of producer that when aggregated, represent a stable source of supply for the capacity.

Under the current rule, the pipeline authority and producer in the group would have to routinely engage in a series of short-term capacity releases to shuffle capacity back and forth between the producer in the group as production levels fluctuate.

The pipeline authority would hold the capacity notice time for the benefit of the producer group, that would facilitate Wyoming's innovative effort.

Fourth, it should be open to shorter term contracts. Not all producers have a production forecast that can support ten year agreements. Agreements with three to five-year terms might be acceptable to a producer, but are not likely to be made available at reasonable rates.

Compressing ten years of revenue requirements into three years won't work. To shoulder out-year risks of expansion projects supported by short-term agreements, pipelines are going to need market based rate authority to have a balanced opportunity to earn reasonable return.

Periodic true up calculations and rate caps can restrain the pipelines to a reasonable return.

These four suggestions highway a way a producer can avoid taking all the risks. If these are all unacceptable, the only agreement can be offered to a producer is one with a ten-year term and fixed rates, expansions will still get built.

It will just take larger and longer price signals to justify individual producer-shipper decisions to bear all the risks.

In the meantime, capacity not built or delayed is capacity held off the market.

Thank you.

MR. MILES: Thank you.

Our next speaker is to give us a perspective on environmental impacts of developing coal bed methane technology, gas availability in the west.

Brad Bartlett is an attorney with the Land and Water Fund of the Rockies.

Brad.

MR. BARTLETT: Thank you for the opportunity to speak today.

MR. MILES: You might want to put the microphone closer.

MR. BARTLETT: I am counsel for the Land and Water Fund in Boulder. I work on public lands issues in Colorado and New Mexico and specifically the impacts of oil and gas development on federal public lands.

In my work I represent western ranchers, hunters, tribal members, conservationists, grass root citizen groups and grass root tribal citizen groups, all of whom struggle daily with current and proposed environmental impacts of development on public lands.

I'm an ardent believer in our public land system. There is no greater democratic idea than the public lands held and managed in public wealth.

There can be a disparity of influence that has become inherent and omnipresent in our public land system whereby very powerful influence that often serves to dwarf the power and voice of every day citizens.

I'm here today to talk about the myth that public lands are, quote-unquote, locked up from oil and gas development.

There are very few areas of our public lands that are off limits to oil and gas development. Furthermore, because of the vast majority of federal public lands being open to development the issues around the west is how do we do oil and gas development on public lands right.

By way of background, which I believe Roger referred to, the Rocky Mountain west contains more natural gas than any other region in the lower 48 states.

It holds nearly 41 percent of the estimated proven and potential gas reserves in the U.S. and produces about 20 percent of the nation's natural gas.

Currently, Rocky Mountain west is home to more than 110,000 permitted wells on our federal public lands.

With regard to coal bed methane, it is a relatively new industry to the west. Coal bed methane is natural gas trapped in coal seams whereby water pressure causes the gas to be absorbed on the surface of coal.

To release the gas, methane operators drill coal seam aquifers and pump out groundwater.

This reduces water pressure, allowing methane molecules to escape to the surface.

Most methane wastewater is discharged into our nation's rivers or streams or unlined impoundments.

While potentially potable, this water contains salts that can permanently impact soils, unable to support plants and unusable for livestock and wildlife.

In addition, it dries up streams and

spring fed creeks.

Most states don't require operators to obtain water rights or beneficial use permits to take the water out of the ground for the methane development.

Regardless, the west is a key region for coal bed methane production, the most prolific coal bed methane production is in the San Juan and Powder River in Wyoming.

Again, there is an impression federal lands are off limits to federal development. However, statistics from the federal land management agencies themselves hold this to be untrue.

If we look at BLM public lands on a state by state basis, starting with Colorado, Colorado, there are approximately 16 million acres of BLM public lands open to oil and gas production at this time.

There are approximately 600,000, or less than 4 percent of those lands that are closed, specifically closed to oil and gas development.

In the state of New Mexico there are approximately 28 million acres open to oil and gas development on BLM public land.

There are approximately 1.3 million acres closed, or 4 percent of those lands closed to oil and gas development.

If you look at the Rocky Mountain west on the whole and Rocky Mountain states in totality there are approximately 110 million acres open to oil and gas development currently. That is 93 percent the public lands out there, and only 7 million closed to oil and gas development, about 7 percent of the BLM public lands in the Rocky Mountain states.

The lands closed to oil and gas drilling represent the modest amount of protected areas in the west where oil and gas drilling has been deemed by congress or the executive to be inconsistent with the lands's special or intrinsic values.

What about the other 93 percent of our public lands? The vast majority of these public lands are truly open for business.

Look at the Powder River Basin which was alluded to earlier. In Montana, BLM is currently calling for up to 26,000 wells to be drilled over the next 20 years.

In the Powder River, they are calling for drilling 40,000 coal bed methane wells in the next ten years. And San Juan Basin, with approximately 18 to 20,000 active wells, they are calling for an additional 10,000 wells over the next ten years and would allow for 36,000 acres of additional land disturbance, impacts on thousands of cultural resources and tens of thousands of additional air pollutant (inaudible).

Given the current proposed level of oil and gas development in the Rocky Mountain west, the question many Westerners are asking is not how we accelerate oil and gas production on the public lands, but how do we do such development responsibility, by safeguarding our nation's special public lands, the majority of which are not off limits.

By protecting clean water, wildlife and traditional economies. By holding the industry accountable for cleanup and mitigation. And by any harmful subsidies that discourage development and use of renewable energy.

Some federal agency -- agencies should be providing a greater level of accountability. In addition the industry should be taking the lead as land stewards and not simply land developers.

In so doing the government and industry should work to prioritize the best long-term interests of the western communities rather than emphasizing streamlining, fast tracking, expediting production over the short-term planning horizon, they should be prioritizing the health of the land by directing as required by law that lands impacted by oil and gas are fully restored and fully reclaimed.

They should be working to require and utilize alternative drilling and reclamation technologies as a means of protecting the west's special places on public lands and as a means of reducing the footprint of conventional oil and gas development.

They should formulate alternatives to oil and gas development emphasizing stable long-term production whereby mineral development would be managed to minimize boom and bust cycles providing for sustainable economic growth and associated revenue streams.

In sum, industry and government need to work with citizens to reduce the gigantic footprint now being left on public lands by current oil and gas developers.

MR. MILES: Thank you.

Our next speaker will talk about the role of liquefied natural gas and gas supplies.

He is president of Sempra Global.

MR. HULSE: Thank you. I appreciate the opportunity to be with you today to talk about the North American gas supply situation and THE role of liquefied natural gas can play to ensure we have plentiful gas supplies for several years to come.

In the brief moments I have I would like to focus on some key understandings and a few recommendations that are necessary for LNG to help solve our gas supply problem.

I will be referring to a hand-out that was at the door with the gas supply pictures.

First, I think we must first understand we need to recognize we actually have a gas supply problem. The problem is long-term and will require long-term solutions.

Please refer to slide 1.

What is shown here is a history of U.S. consumption of natural gas since 1970 and the production of gas in the lower 48 states.

Since the deregulation of gas in the mid '80s, U.S. demand has outpaced production and the gap is widening.

Canada has stepped in to fill that gap. But the days are behind us. Our neighbors to the north will no longer be able to make up the difference.

We need to look to new sources to obtain our supplies. There are widely diverse opinions as to the future, as you can see from that graph. It's Sempra's opinion that we have peaked production in North America and that North America will no longer be able to produce enough gas to maintain current levels of production let alone meet projected increase in demand.

We feel there have been overly optimistic production projections and very speculative demand projections.

The fact is, we cannot consume more than we can supply and prices the rise until there are sufficient reductions in consumption to bring supply and demand into perfect harmony. We are experiencing the economic impact of a supply shortage.

Second understanding. We need to

understand we will not be able to solve our gas supply problem with what I call the domestic drill bit.

If you will refer to slide 2.

Here we have a similar curve showing oil consumption and our domestic production.

Note we peaked domestic production in oil in 1970. Even the additions of Alaska, which were very significant, and deep water Gulf of Mexico, which we are starting to see, could not overcome the decline. We now import over 60 percent of our oil consumption.

We submit U.S. gas production will follow a similar course.

Third understanding. The world has abundant supplies of proven gas reserves.

If you will refer to chart 3.

There is roughly 6,000 trillion cubic feet of proven gas reserves in the world. The world's gas users consume 85 trillion feet a year. Therefore, we can supply the world market for roughly 70 years.

North America represents 31 percent of the world's gas market. When domestic gas supplies are between $3.50 and $4 on a sustained basis, we believe there will be actual competition amongst gas suppliers to capture a place in this, the largest gas market.

What do we need to do to enable LNG to enter this market? We need to expeditiously permit and construct several receipt facilities.

We are severely lacking the necessary facilities to import large quantities of LNG to fill the supply gap.

When we peaked oil production we were already importing 30 percent of our supply needs. It was easy to ramp up imports.

We do not have the same luxury with our current gas situation.

Two. We need to ensure that the public, to the public, that all the new facilities will be constructed to the industry's more stringent safety standards.

We can take no shortcuts here. The LNG industry has enjoyed an impeccable safety record for more than 35 years. We should do nothing to jeopardize that record. Public confidence is at stake.

In the United States, because we had a brief moment where we entered the LNG market and let it idle for 20 years, we need to look at new standards and update our standards and make them current.

There are better standards in the world today.

Three, we need to adopt uniform pipeline gas quality specifications. We must make sure we are not limiting our ability to attract multiple gas supplies by demanding restricted pipeline quality specifications.

Let me give you an example. In California, the California Air Resources Board adopted a very stringent gas supply standard to meet the requirements of compressed natural gas vehicles.

Now this is a very small amount of consumption. Yet, it has set the pipeline quality specification for Southern California. Seems like a benign act.

But if we were to leave that standard in place in the pipeline systems in California we would not be able to attract a single supply source that currently produces LNG in California without modifying the LNG.

If we were to revert to the pre CNG

vehicle specification we could attract supplies from 12 countries that currently produce LNG.

Now that is not just a California problem, we are looking at it as a domestic problem in the U.S. That needs to be addressed. And we need to be able to not limit the supply sources of LNG if you are to solve our LNG or our gas problem through imports.

It's only by acknowledging that we have a gas supply problem and that the solution rests with imported gas in the form of LNG will we be able to avoid future shortages.

History has shown that shortages lead to higher prices, false allegations and the loss of credibility with customers and in the court of public opinion.

Thank you.

MR. MILES: Thank you.

Our next speaker is Bill Bingham, acting business leader for the Commodity Unit at the National Energy Board.

MR. BINGHAM: Thank you and good afternoon.

Chairman Wood, Commissioner Brownell, I want to thank the Commission for providing us the opportunity to be here this afternoon and speak to you on Canadian gas supplies.

Gas exports from Canada to the United States have more than quadrupled over the past 20 years. To reach this level Canada exports more than half its domestic gas production.

During calendar year 2002, for example, Canada supplied the United States with 3.5 Tcf of gas or 56 percent of its gas production.

These exports satisfied over 15 percent of U.S. gas needs, most in the midwest and northwest markets, but a Tcf found its way to the western market.

Canada has been exporting a lot of gas, and we expect we will be able to continue to do that and be a reliable supplier for some time.

Of note, though, last year also broke the long string of annually increasing exports to the United States. Actual exports of gas production were down slightly in 2001.

At this point I would like to take a few moments to examine recent performance of the western Canada basin and the future of the Canadian gas supply.

I brought along a hand-out in the back of the room.

The first chart shows gas supply in the western basin has been responding to drilling, with you in an ever diminishing fashion. At the beginning of the last decade a doubling from two to four thousand wells annually increased gas supply by 30 percent.

More recently a doubling in drilling from four thousand to eight thousand wells annually has only increased gas supply 10 percent.

The modest response or as I mentioned a moment ago, the slight decline in production last year, as was suggested a moment ago, has led many to speculate the western basin has finally declined.

Alberta, which accounts for about 80 percent of gas supply has been experiencing declines in quarterly production since late 2001. However this decline has been offset by growth in British Columbia for a while, but recently British Columbia joined Alberta with declines.

On a brighter note, producers have been responding to price signals. Now that our rainy and snowy weather has passed, drilling rigs are drilling at a rate exceeding that of 2001.

If this continues production from the western basin should stabilize from last year.

The third chart presents the outlook of gas supplies over the long term. This was taken from our recently released supply and demand report entitled Canada's Energy Future, Scenarios for Supply and Demand to 2025.

We used the scenario approach to better understand the forces impact on Canada in the future and issues associated with the evolving gas markets.

We created and explored in detail two different plausible energy futures for cad Canada. These are called supply push (inaudible).

I don't want to spoil the fun by getting into the details, but I will share the results with you.

With those scenarios it looks like conventional gas production from the western basin will remain essentially flat to the end of the decade, at which point it will start to decline.

With this, we expect an accompanying series of adjustments ranging from increases in gas production from other basins to development of unconventional gas.

Colleagues on the panel have discussed the growing importance to U.S. gas supply. Our scenario also indicate CBM will be perhaps as high as 4 Pcf per day.

However, for the time being development is in a very early stage. We have about 20 pilot projects right now.

We (inaudible) for a whopping 10 million cubic feet a day order of magnitude than my friend have been talking about. But we are just getting started.

A recent development in Canada was the filing of a preliminary information package by the producer group that aims at development of the Mckenzie gas project.

An application to the board is expected by next spring. The time line is for regulatory approval by 2006, construction during the summer seasons of 2007 and '08, and for gas to flow in 2009.

Initial design of the pipeline is 1.2 Bcf per day with a easy expansion to 1.9.

In this connection we are aware of

exploration being conducted in the area and is apparently very promising.

In summary, the days of easy production increases in Canada may well be behind us.

However, continued development of this large resource base, potential development of CBM, further offshore development on the East Coast and northern gas, Canada will remain a significant producer and primary supplier of natural gas to the United States for sometime.

Thank you very much.

MR. MILES: Thank you.

Our next speaker is to give us a Mexican update.

Francisco de la Isla, general director, Economic Policy Unit, Commission of Energy Regulation.

MR. De la ISLA: I appreciate that. I want to thank the Commission, Chairman, Commissioner and all of you for your patience to listen to me the next few minutes.

I will try to give you a very brief overview of what the supply is in Mexico.

I have to say, as I'm sure most of you know, it is in stark contrast with what happens in Canada and the U.S.

Your energy sector is driven by market forces. Ours, legal monopolies both in the power sector and private (inaudible).

As you know, Pemex is the legal monopoly in production of natural gas. Also, it's a consumer. This has an importance I will try to underline later.

In 2002 Pemex produced 4.1 Bcf daily, almost half of which it consumed under a number of purposes because, as you know, it's an integrated producer that ranges from basic petrochemicals to refining and exploration and production.

Total demand was 2.8 Bcf. So we are certainly talking of varied degrees in importance.

In the last few years, though, demand has gradually outpaced production. The main reason for this is that most of the production was associated gas in the southern Gulf of Mexico. And because of that production was tied to the policy mandating the oil output.

It was not until 1998 that Pemex started producing non-associated gas in a large scale.

This is basically reserves situated or located in the northeast of the country, southwest of Texas, for your reference.

Another important part to this continuous slack or lag in the production with reference to demand is that from a number of years ago, CFE, the power monopoly, decided to concentrate on natural gas as a source of electricity generation and, therefore, started developing all its expansion plans under this type of technology.

Now, current forecasts shows, these are published and annually by the Secretary of Energy, is that this trend will keep on for the next few years.

For the period 2003 to 2010, domestic amount is expected to grow at a 9.1 percent rate.

Supply on the other hand is 1 percent lower than that. That means imports will have to grow around 13 percent yearly.

Now this is an outlook made 2002, and we expect it will be corrected downwards the next year, because of current market conditions.

Now, imbalances resulting from this excessive demand have to be tackled in some way. The country has remaining reserves of 65 trillion cubic feet, most of which are in the northeast of the country.

21 trillion of these are proven reserves, and of those, slightly less than half are in the south.

Apart from this effort, this natural resource asset, Pemex is increasing production of natural gas.

It is doing so in various ways, under specific investment programs called strategic programs, gas updated programs.

Also through a number of contract services that it has tried to offer, in which it offers at specific areas for development through private companies.

It's also doing some efficiency gains, making more available output for the market.

Throughout all of this is an expected fall, not acute, but an expected fall starting 2004 with regards to imports.

For the future years we are in need of imports from U.S. and LNG. Imports, as you know, come basically from the south of Texas and to a lesser extent from Caribbean and other places.

Currently there are four LNG projects in the Pacific, already mentioned by Jeff. Four in the Baja peninsula, four very close to the border, and the others a few miles away.

Rick, could I have the second of the slides, please, just to give you some figures about that.

All these applications have been made, put forward to the Commission. They have been analyzed.

There has also already been one permit granted.

For the other three, response is to be made shortly.

Now, we don't know how many of these projects will be put in place. But we expect one or at least two to start operations as scheduled.

What this means is a new source of supply for the northwestern part of Mexico. But because there is not really a great amount of demand in this area, most of this gas would go into the U.S.

On the other side of our -- on the Gulf side, there is a project basically for generation purposes.

It is at public bid by CFE and it's

expected, at least stated to start in 2006. Basically, that is the current outlook on supplies.

I would like to make just a few quick conclusions.

We have slight deficit for next years. We are expecting energy and imports to fill the void.

Even though we have the resources to tackle this problem, because it is partly political it is in the hands of government and congress to turn that potential into a reality.

Thank you very much.

MR. MILES: Thank you.

Our last panelist is Kirk Morgan. He is going to speak on interstate pipeline deliverability issues. He is vice president for Marketing and Regulatory Affairs for Kern River Gas Transmission Company.

MR. MORGAN: Thank you. I want to thank the Commission for the opportunity to present Kern River's views with regard to construction in the west.

First, I would review recent infrastructure developments.

And secondly, to describe some of the market changes that have occurred since new infrastructure has been added.

Thirdly, I want to discuss future market drivers.

Beginning in 2000 the need for energy infrastructure investments was evident across the entire energy supply chain. Exploration and production, gathering and processing, power generation, interstate and intrastate pipelines, as well as electric transmission.

There has been significant new capacity brought on line. In the pipeline area, 1.6 Bcf of new interstate capacity has been constructed to California.

Kern River represented a little over a Bcf of that capacity, and there is another 320 million cubic feet per day on the way with El Paso's power expansion.

Nearly 4,000 megawatts of new power generation have been completed in California, Arizona, Nevada and Baja, California, and there continues to be over 8,000 megawatts currently under construction.

We believe reserve margins have been

restored and indeed, capacity has been over built in some areas forcing some construction plans to be suspended or deferred.

Wyoming production alone has surged over one and a half Bcf a day since 1998, and overall production is now over 6.2 Bcf in the northern Rockies.

Despite these investments capacity constraints and regulatory barriers continue to restrain gas on gas competition.

In California, SOCAL take-away capacity is adequate to ensure reliability but insufficient to provide gas on gas competition.

Supply basin fundamentals have changed and California wants additional Rocky Mountain gas. But SOCAL gas capacity allocation procedures prevent 3 hundred million cubic feet a day of Rocky Mountain gas from competing in the market.

There is a preference for historic gas flows, and SOCAL needs to implement the gas industry restructuring.

Kern River currently provides the lowest cost delivered gas in California. Yet, the CPC has ordered utilities to take El Paso capacity guaranteeing full rate recovery without consideration of competing options.

Projects are risky enough without intervention to tilt the competitive playing field.

As mentioned earlier gas supply fundamentals have changed. Permian and San Juan production is flat to declining, and growing Arizona and New Mexico markets will increase pressure.

Increased reliance on these supply basins would be misguided at this time.

LNG supplies may have a role but are uncertain due to risk involving licensing, scheduling, construction costs, politics and safety and environmental concerns.

Also, as mentioned, western Canada is recently in decline with lower initial production rates and high decline rates.

There is also the looming issue over Alberta oil sands development which threatens to curtail exports to the U.S.

Mckenzie gas may be on the way within the decade but there are two Bcf of available capacity on trance Canada which could consume the Mckenzie gas. There is no guarantee that gas will make it to western markets.

Rocky supply is proven and pipeline projects are predictable relative to LNG or frontier pipelines.

Kern River recent expansion has changed the market. Almost overnight gas prices have been reconnected in the region. It opened with a 95 percent load factor and is running at full capacity today.

On average we now deliver 900 million cubic feet of gas to California, approximately 18 percent, up from 7 percent prior to the expansion.

Canadian and southwest supplies are being displaced by approximately 400 million a day and 200 million respectively.

Still, there is need for new infrastructure, but the interstate pipelines are not speculative investments. Long-term contracts are essential to attract investment capital.

However, the financial condition of many parties is not conducive to long-term contracts. Production aggregators are less prominent in the marketplace and producers must get their gas to trade in hubs.

There is a need for supply area infrastructure, and producers will need to step up and take capacity to ensure their gas gets to trading hubs.

For example, on Kern River's recent expansion, 94 percent of the capacity was taken by electric generators and market affiliates (inaudible).

Only two percent of time was subscribed by producers.

Supply area projects need producer support.

Finally, recent expansions were driven by explosive market growth in power generation and true capacity shortage.

Changes in supply basin preference and pipe-on-pipe competition will help drive new efforts.

Kern River is well positioned, can be economically expanded, and we are prepared to make additional investments to meet market requirements.

Thank you.

MR. MILES: Thank you.

Any questions, observations?

Mr. Chairman?

CHAIRMAN WOOD: You and Brian had an interesting, I guess book ends. Not quite book ends, but comment on what it takes the producer to get into supporting some pipeline expansion.

Would you agree with the four points Brian laid out, if you can recall them?

MR. MORGAN: I guess I think particularly small producer have been used to selling gas at the wellhead.

Market used to include Enron and a lot of the large marketers who have been willing to take the risk of capacity have backed out of that and now producers are finding it difficult to get their gas to trading hubs.

I'm not sure I recall each of the four points, Brian. Do you want to say what they are again quickly?

MR. JEFFRIES: The ability to do flexible contracts, referred to as index to index contracts. Suggested that some relaxation of the shipper hold title rule.

The ability for pipelines to have to partially support a project with short-term agreements, provided the pipelines an opportunity for market based rates on the back end gap, if you will.

And the fourth.

CHAIRMAN WOOD: Capacity release.

MR. JEFFRIES: Thank you very much. I'm glad you remembered.

MR. MORGAN: On the index-to-index deals, we do support that. We have done those on Kern River. We think they should be continued.

I recognize the recent order has proposed eliminating those. But I do think they set the right price signals.

With regard to price caps on capacity release, I suppose we think that just forces transactions into the gray market. They are not really an effective restraint on control of prices. Marketers and producers will just bundle service and do by self transactions.

Shorter term contracts, Kern River has offered differentiating rates, we have ten and 15 year rates. I realize that is not what you are necessarily looking for.

But pipelines are very long-term investments, and the business is becoming quite risky. We have chased our fourth shipper into bankruptcy here recently.

And between creditworthy standards and long-term contracts, we need to have both strong term -- long-term contracts and creditworthy shippers to attract investment capital.

MR. JEFFRIES: If I can offer up just a partial rebuttal to a comment he made about producers stepping up to the plate.

It's true, the shipper you described on the Kern River expansion but virtually a hundred percent of the trail blazers reached expansion supported by producers, a goodly portion of the grassland expansion are producer supported.

So it's not correct to say producers are not stepping up. It's just an issue that is increasingly difficult for them.

For many producers, going into the gray market to get the value of their capacity is not available to them, they are not all in a position to be a marketer and with the merchant aggregators out of the business, we need a new class of people to step up, smaller producers step up and take capacity, we need to create some flexibility for them to be able to do so.

MR. MORGAN: I agree. Actually, Kern River was originally built as a producer pipeline, probably 80 percent of the vintage capacity is held by producers.

So it's just an observation of the latest expansion, producers who were complaining the loudest about price disconnects elected not to participate.

CHAIRMAN WOOD: Francisco, a question for you. I notice there were four potential permits on the northern Baja peninsula. How many of those do you think will be ultimately in service?

MR. De la ISLA: Well, as I said before, it's just a matter of feeling here. There's no -- well, I think all of them. But we have really just the feeling that maybe one, two at most will be functioning.

CHAIRMAN WOOD: From the permitting side, that requires approval from the CRE. And who else?

MR. De la ISLA: It's local authorities particularly. And, yes, we (inaudible) that enables the operation of a company on technical and economic returns.

But whatever has to do with the

environment is part of federal -- (inaudible).

CHAIRMAN WOOD: Thank you.

MR. MILES: Other questions?

Yes?

MR. IRVIN: If I could, Jim Irvin, with the Arizona commission.

This is -- you indicated LNG is a life safer. Yesterday, the gas days, the outlook didn't quite put it as a life safer. I'm looking at the comments made by Kirk.

Would you agree? Kirk talks about LNG supplies may have a role. But the uncertainty there is tremendous. What is the reality?

We've got one LNG permitted in California. That obviously is limited.

What is the reality of getting these things? And how much can it really reduce or can we count on that reduction?

And the last question would be, do you require the same long-term contracting that the regular natural gas requires?

MR. HULSE: Let me see if I can address that.

The first question, I think you need to understand that we do not think you will ever solve our gas problem with the drill bit. I go back to the oil production as somewhat history and evidence of that.

We are going to have to import gas or we are going to have to eliminate our dependency upon gas as a fuel.

If we want to keep the infrastructure we have designed, if we want to keep the power plants we have built, if we want to enjoy the environmental benefits we have gained from gas, we will have to find gas outside of our domestic production.

The world has sufficient supplies for that.

I think it will flow here when it's economic to do so. And the price range between 3.50 and $4 will cause sufficient gas supplies around the world to flow here that is currently stranded to a supplier either looks at it and says I either need to wait 70 years to get this gas I found to market or I need to get a place in the market.

So I think from a stranded gas scenario the suppliers will capture the market on that basis.

Is it viable? Yeah, I think it's viable, as long as we can build sufficient receipt facilities to get it here.

And the suppliers know that there is a reliable market, and the price signals are there to allow the infrastructure to be built on the other end, which is a very large infrastructure to get the gas supplies here but you know, we even need to retool or we need -- in other words, retool everything that consumes gas and switch to another fuel or we just need to get more of the same fuel.

MR. MORGAN: Let me follow up on that. LNG deliveries would be very high pressure deliveries.

Do you feel like the intrastate from a structure in California is sized right to accept the kind of pressure that LNG would be delivering generally, a continuum from the east to the west where it has a lower pressure system?

MR. HULSE: The ideal places to bring LNG into North America are either in the Gulf Coast, where we currently have plenty of take away pipe systems to deliver it to the markets in the north east and midwest and west coast, or put it at the end of the pipe, which means right near the market, the northeast or the California area.

So those would be the most ideal places to site this.

Gas, you know, the LNG is not high pressure when it's stored. It's at just slightly above atmospheric pressure. It's in a liquid state.

We pressure it up to put it in whatever pipeline system it will go in. You do that with pumps, not compressors, because it's more efficient to do that.

So in a liquid state it's pumped through a heat exchange, then it converts after it already has the driving pressure behind it, it converts back into a gaseous state.

MR. ELLENBECKER: (Inaudible) Wyoming commission.

What are the missing congressional production incentives for natural gas.

MR. BIEMANS: I don't know that requires production incentives so much (inaudible) to do what we do well, that is get on the land to extract the resources. (Inaudible).

MR. BARTLETT: I think there are plenty of opportunities to withdraw it from the land. To the extent it's done wisely (inaudible).

I think that is the message I conveyed here today. There are substantial environmental impacts and impacts on local communities from going in, putting in ten to 20,000 wells in a community, impacts on ranchers and native communities and impacts on people who are from these communities and live on this land.

So you have to take those into account. You just can't go in and open up this place and have a cycle that is not going to have irreparable impacts both environmentally, culturally, socially to these communities and you have to take those things into account and try to do it wisely.

I failed to mention, I did bring some literature, I brought a big old map in the back that kind of outlines and identifies the areas of the west where oil and gas development is currently happening. It will give you a sense for the size of the development currently happening throughout the Rocky Mountain region.

MR. MILES: Thank you. I think on behalf of the Commission and audience we would like to thank the panel for their presentation.

(Applause).

MR. MILES: If I can have the next panel members come up front, please.

(Recess.)

MR. MILES: Let's begin with your next panel on electric transmission.

For those of you who were here for the first panel, there was a talk about electric transmission and the role it will play in meeting energy demand in the west.

But this panel will focus on electric transmission.

We asked them to address can the electric transmission system get generation to load centers.

With that, we will start with the first speaker, Mr. Ronald Montagna, Senior Realty Specialist, Bureau of Land Management, White House Energy Task Force.

MR. MONTAGNA: Good afternoon. On behalf of the White House task force and BLM, I want to thank the Commission for inviting me here today to briefly discuss right-of-way planning on western federal lands.

This is a process that has been under refinement for about 25 years. I have about five minutes to explain it.

I will briefly discuss the current efforts by the BLM and Forest Service, Department of Energy through Argonne National Laboratories and, hopefully, FERC, with assistance from the Western Governors Administration and Western Utility Group to identify and analyze where appropriate designated right-of-way corridors on federal lands.

Before I continue I need to present two definitions that will be helpful in this discussion.

Could I have slide one, please?

MR. MILES: Yes.

MR. MONTAGNA: When we talk about right-of-way corridors, they have rights of way in them.

A right-of-way is the authorization to use a particular piece of either public or Forest Service lands.

A transportation utility corridor is a parcel of land being used as a location for one or more of these utility rights of ways.

The important definition, a designated right-of-way corridor, a parcel of land with specific boundaries identified bisect of water and land use planning process or some other management decision as being the preferred location for existing and future right-of-way facilities.

The corridor may be suitable to accommodate one or more type of right-of-way or right-of-way use or facility or one or more right-of-way uses or facilities which are similar, identical or compatible.

A designated corridor may already be occupied by existing utility facilities. And it has adequately analyzed to provide a high degree of assurance that in being identified as a designated corridor, it can accommodate at least one new utility facility.

That is I think two sentences there. Okay.

Now, before an electric transmission line can be sited on BLM land, a formal land use allocation decision must be made. These decisions are made after appropriate NEPA analysis and decision must be in conformance with an approved land use plan.

And at this time the BLM has very few valid designated corridors. Therefore, each proposal for a new electric transmission line must receive a new comprehensive NEPA analysis and land use plan conformance review.

In most situations it will require a land use plan amendment.

Slide number 3, please.

To streamline this application by application review, the BLM and Forest Service with its partners endeavors to implement the corridor designation provisions of the Federal Land Policy Management Act.

Hopefully, with adequate budget and personnel support, the federal members of the partnership will begin to analyze the priority corridors in the coming fiscal year.

In the next several months the BLM and Forest Service, in consultation with its partners, will determine if one or more regional analysis will take place, or if the corridor designation process will continue on a long-term local land use plan by land use plan basis.

It is currently envisioned that when the analysis is complete there will be a west wide system of designated right-of-way corridors.

Can I have slide 3?

When corridors are designate a proposal for a new transmission line from say Filmore, Utah, to Salt Lake City, will be limited to analysis of the proposed action and no action. Analysis of other reasonable alternatives and the cumulative impacts and other critical aspects will have been completed in the designation process.

It is the land use philosophy of the BLM and task force that a system of designated corridors will significantly streamline the siting process for future individual proposals.

The use of designated corridors will also reduce the proliferation of individual rights of ways and reduce the negative environmental impacts of right-of-way construction, operation and terminations.

Thank you.

MR. MILES: Thank you.

Our next speaker is to talk about major transmission constraints. Armando Perez, the director of grid planning for the California

Independent System Operators.

MR. PEREZ: It's a real pleasure to be here today.

My discussion today will be based on something we call STEP, an acronym for Southwest Transmission Expansion Plan.

STEP came about because of discussions between the California and colleague of the Salt River project.

It came about because we started to look in the fall of '02 of the amount of generation coming into the Nevada region, the Arizona region, the Mexico region, and immediately we realized we were going to have a couple problems.

Problem one was going to be congestion and congestion management, and I'm not going to talk about that today. That will take 20 minutes.

The second one was, because transmission was not being built, it brought up the issue about congestion and economic impact on ratepayers.

We would have to determine what the impact was and how much transmission should be built to try to eliminate all or most of it.

To do that, we decided to have a meeting with everybody that we could think of in the States that I mentioned, plus Mexico. And because San Diego is such a great place to meet we met there. We did that.

The first meeting brought three problems to us immediately. One was the resource adequacy issue that arises when we have 50 people sign up and a hundred showed up and I have no food.

Second was congestion on the food line.

The third issue and most important to FERC is the fact that we have to call for another order of food and we were not covered by a contract, so we had to pay real time prices.

The first four slides in here will give you an idea of the type of participation we had at the STEP meeting.

That is all I wanted to show you, a lot of breadth, a lot of width and a lot of interested people.

We met because we really wanted to find out exactly what people in these states and Mexico thought about additional generation we hadn't thought of.

Especially we wanted to find out about transmission projects they have in mind that they have not notified me about.

How did we do that? Well, slide 6 gives you an idea of what we have in mind. In Arizona we have 6600 megawatts of new generation planned. CFT or the portion of Mexico under government (inaudible) is 1660 megawatts, and in Southern California we have 2120 megawatts of new generation.

Blue line, zero. Why? Well, probably a couple of reasons. One is, there was no requirement for anybody to build transmission.

Second, probably not a very good economic incentive to build. And more about that later.

After a series of meetings, what we came up with is kind of a wish list of what everybody thought they wanted in terms of transmission.

One was the conversion of an Arizona line being presently operated (inaudible). So we are looking at that.

We are looking at additional facilities between Arizona and Southern California, both in an additional line between Palo Verde and another between the Palo Verde north substations. Also additional line in Imperial Valley going north, or south to serve the San Diego load. And additional transformer capacity at McGill substations.

We had a whole bunch of different talented engineers who came up with 21 different alternatives that would put this together that was going to solve the congestion problems.

And we limited ourselves in most studies to (inaudible).

Those 21 alternatives were put through a series of electrical tests and stability analyses. (Inaudible) We brought those down to four AC alternatives and two DC alternatives.

Now I have a fellow within my group with a whole server (inaudible) 24 hours a day, seven days a week.

Economic analysis now beginning to be complete. We have a meeting yesterday and we presented the economic results for the first four AC alternatives. The next two will be done late.

End result will be to determine based on the congestion costs and production costs exactly what transmission is justifiable to be built.

Then we will do that and put it through the regulatory process to get the proper permits.

From then on, we hope this will move into the secret process that we don't talk about and hopefully in the future we would like to start an additional group of subregional groups, possibly with the northwest (inaudible) the ones we have in mind.

That is pretty much where I am.

MR. MILES: Thank you very much.

Our next speaker will talk about Bonneville's role in all this. Vicki VanZandt. She works with Bonneville Power Administration, is vice president of Operation and Planning.

MS. VAN ZANDT: Thanks for the invitation to address you today, Chairman Wood and Commissioner Brownell and state commissioners.

Where does Bonneville fit in in all of this? For the most part we haven't built anything of significant size in about 15 years as far as transmission infrastructure.

We have used controls and low costs and reactivated conditions to accommodate load growth in the market as it's matured.

We have pretty much used up the margin in the grade and now need to build infrastructure and have some under way I will describe in a minute.

We heard a little bit earlier in the session this afternoon that the northern half of the interconnection was pretty dependent on hydro.

That is not just the northwest part, but northern California, as well. So the grid was built around it. Loss of hydropower generating resources or changes in hydro-generated patterns cause stress the grid was never designed to withstand.

You may recall two years ago, second driest year in our history, a 54 million acre feet in average on the basin, about 106 is average. So a very dry year. I have never seen in the almost 30 years I have been at the Bonneville power flowing up the intertie in the middle of summer from California to the northwest. Just shocking.

So, but we saw that. So we saw transmission power flows that were very unlike, very unlike what we have typically seen. It's usually in a north/south direction.

So the system is exhibiting signs of stress, particularly in the summer. Even though the northwest is a winter peaker, our summer peak is approaching our winter peak. It's very close now.

And summertime is when the grid operators worry the most, where resiliency to disturbances is less than we need, and small changes in flow over a path, for instance, results in big changes in buss voltages . That is one symptom.

Another is that we have to take big reductions in capability, what we can offer as well as available transmission capacity when we have relatively minor pieces of the infrastructure out of service for maintenance. That is another symptom.

Grid operators in the northwest are pretty concerned about the rise of near-misses. We had a voltage instability incident and a path that was pretty hard to control within safe operating limits.

These examples are just within the last 45 days.

Infrastructure plans to reinforce some paths are under way. They have a few purposes, to reinforce the load centers in the northwest, to relieve congestion on some major paths and to restore some reliability margin back into the grid, which is my favorite reason.

It's disconcerting to see voltage fluctuations in the middle of the night just because of the particular generating pattern.

So, woefully small, I apologize. Should have brought an overhead. But here are some of the things that we have under way.

I think one was referenced in an earlier presentation. A small nine mile reinforcement of the Puget Sound area. One of the most difficult things to site in my recollection.

In the mid '80s it was difficult to site the coal strip section, this nine-mile section makes that pale by comparison.

Also from Grand Cooley, the biggest hydro resource in the northwest, over to the Spokane area, that one provides some capacity for the market.

It also helps us meet our contractual obligations.

So sometimes when load goes away, that's not always good for transmission congestion. Location is exceedingly important in both generation and in -- where loads are.

So sometimes a sink in the form of load on one side of the constrained path, when that goes away there is more pressure on the cut plain.

So the Cooley belt transmission project is under way, under construction, should be done by next fall. Not this coming one, but a year from now.

The Kingly Lake construction project, we expect to have that done by this December. That is important to meet Puget Sound load and also for Bonneville to meet its treaty obligations to the Canadians and entitlement return.

The third one is down the center of Washington state. It goes roughly from the Wenatchee area down to the tri-cities or Hanford area.

That has a lot of benefits, mostly reliability benefits. But it also creates some capacity through the center of the state and, surprisingly, on the corridor, where it would be more difficult to build.

So those are the ones under way. We are also replacing our merc/arc valves in the northern terminal. We are replacing 30-year-old merc/arc valves to make sure we can retain 3100 megawatts down to (inaudible) indefinitely into the future and some serious capacities in the center of the state.

Those are not as hard to do as siting lines. They tend to make lines look shorter so you can push more power down them.

So we are doing that as well in a variety of transformation items.

But this is just a start. It really is crippling congestion, it makes the symptoms of reliability problems back off the nose of the cliff, if you will. And it adds capacity for new generators.

But it's not enough.

In addition, we need an improved planning function pretty much right away and suggest it be done on a subregional basis.

Roughly the footprints of the RTOs under discussion would be maybe a good first step.

In the northwest we think the best forum for that would be the transmission planning committee of the northwest power pool and are working with the region to try to make that happen.

Once the plans are made, though, somebody needs to come up with the money and actually have it built. So that's the hard part.

The northwest recognizes this challenge and is taking this up through the RTO's regional review group and other transmission groups with representation for more of the non-jurisdictional entities in our service territory.

Finally, when subregional plans are made, they need to be tied together with the interconnection. I suggest the Signa group would be a good entity to take that up.

MR. MILES: Thank you.

Our next speaker is Dean Perry who will give us a report on the state of regional transmission planning.

Dean Perry is chairman of the Planning Work Group for the Seams Steering Group-Western Interconnection.

MR. PERRY: Thank you.

I would like to share with you what we are doing with significant we, the Seams Steering Group, Western Interconnection, SSG-WI.

A lot you have overheads and things. I was still preparing coming over, so my thoughts are on a Frontier Airlines napkin. I hope I can read them.

You can come up if you want and read them.

(Laughter.)

MR. MILES: We will copy them into the record as though read.

(Laughter.)

MR. PERRY: There are four or five points I wanted to make sure that you understood in relation to the SSG-WI planning work that we are doing.

First of all, I am personally excited about the work we are doing, of course being able to chair the work group doing it.

The western governors started an effort essentially like this a couple years ago. Other than that, the effort we are continuing on now in the SSG-WI planning effort, to my knowledge, I have been involved in planning for too long to tell you, actually, is the only effort I see going on with such wide a scope as what we are doing today.

I think it's going to be something very good for the intersection, I'm very hopeful it will be.

The first point I wanted to pass on to you is it is an interconnection-wide effort. That is significant, I think. To me it is definitely.

Those of you familiar with the earn connections, I think if you can envision the whole eastern United States getting together planning something like we are doing today would be something perhaps very difficult to comprehend let alone pull it off.

But we are doing it in the west, and I'm pretty excited about it.

So it's interconnection- wide. We are studying the entire western states in the work we are doing.

There has been mention to some of the subregional planning groups. A number of efforts are under way, a number forming now in the Wyoming area.

We plan to integrate the work they are doing with the interconnection-wide work that we are doing under SSG-WI.

Too, we will be very complementary to each other in the work we do. We have already seen examples of how the interconnection work we do under significant we will fit very well with the subregional group, the work they are doing.

The second point is that we are focusing on the needs of the market place. I contrast that with a lot of the traditional planning that has gone on in the past which has been more focused on reliability of the system.

We are focusing on what the future market needs might be. We are trying to identify where there might be congestion associated with that and what transmission, actually or non-transmission solutions might alleviate some of those future problems that might be encountered.

So the second point is we are focusing on the marketed and its needs.

The third point I think is important is that what we are doing is a totally open process. SSG-WI, of course you are probably aware, is a forum that was organized by the three proposed RTOs.

The planning effort we are doing, of course they are directly involved, but we are really encouraging everybody to participate.

We do have good participation. The states are very active participants in what we are doing.

The generation developers are helping us in the work we are doing, both private and public utilities are involved. So I think we are being quite successful in making an open process, I feel.

The fourth point I wanted to mention was we are creating a database through the work we are doing, a model essentially of the western system that can be used in the production costing kind of work.

Through the SSG-WI effort that data base is currently being created. And we really would encourage use of that database.

And I think it's important to try to have a common database for the western interconnection so we don't have multiple databases out floating around raising a lot of questions about who is doing what.

I don't know whether we can avoid that or not but we would really encourage a common database and joint use of a database that currently is actually under development.

The fifth point is that the SSG-WI has an open implementation authority. We are doing analytical work and will make that information available.

But then in order to carry the work we do forward, it will require others to step forward and pick up on what we are doing and carry it into the implementation phase.

Again, we have no implementation authority. But we are trying to fill a void I feel is there and, on an interconnection-wide basis currently this study has than taken place.

As far as the study, a quick overview of the studies we are actually performing currently and which we plan to complete by the end of September.

We are looking at two time frames. One is the five-year out time frame, one a ten-year out time frame.

The five-year we are looking at currently, essentially what that looks at, because within five years you can't really build any significant transmission.

So we are looking at into the future, picking five years, what we think will happen with the current transmission resource plans. Again, we are looking at where there is congestion.

The ten-year study we are looking at is a little different because in this case there is opportunity to build transmission or non-transmission options.

So in that case the problem you have there is that of course we don't know how the resources will develop.

So we have picked three scenarios we are looking at, one the coal scenario, one a gas scenario and one the renewable scenario.

In putting those together we have relied on the sponsors of those types of resources to develop the scenario for us.

So the coal folks said they expect so much, so many megawatts of coal being developed and to stress the system and see what might happen there, likewise with the renewable, primarily wind.

So we are looking into the future, looking at three scenarios.

Again, we are in the middle of our studies, but I think I can tell you based on what we have seen so far that looking out ten years, it's pretty likely what we are seeing now and what we will see when we are through with the studies that the coal scenario where you have a lot of development of coal over the eastern part of the system is going to require substantial transmission throughout the system in order to get it to the west coast, renewable a little less, and gas looks like it will require a minimal amount of transmission. Of course, the gas is built near the load.

Anyway, in the work we are doing and the report we will issue will lay this all out. We are currently trying to put together what we think transmission requirements will actually be for those scenarios and we will have those included, the costs and all in the report.

Again, the report, describing current activity, current work, is planned to come out, I will say September, early October time frame is what we are shooting for. I think we are currently on schedule to complete that.

Then that is going to be a fairly high level look at what the transmission needs would be.

So we will carry on beyond that and do additional work beyond that.

Our goal, actually I think I made a commitment to Chairman Wood back in January to get the report out in September. So a report is coming out no matter what's in it.

(Laughter.)

MR. PERRY: It will be a good report.

MR. MILES: Thank you very much.

MR. PERRY: The last thing I was going to mention, if you are interested in SSG-WI again there is a Web site. I need to put in a plug. It's ssg-wi.com. Pretty easy to remember. You can learn all about what we are doing in the planning area.

MR. MILES: Thank you.

Our next speaker is Frederick Stoval, vice president of Policy Development, XCEL Energy. He will talk about industry participation in new transmission infrastructure.

MR. STOFFEL: Thank you. I am Fred Stoval, the industry voice today.

What is that voice? Just a few words about XCEL. We are an industry holding company with four operating utility companies: Northern States Power Company, Public Services Company of Colorado, Southwestern Public Service Company and Cheyenne Light Fuel and Power Company.

Also we are one of the primary

participants in Translink Transmission Company, which is a proposed independent transmission company.

That is one of the primary ways we are looking at developing infrastructure for transmission along the interstate pipeline structure, if we can get there.

I won't talk much about that today, but I did want to mention that.

I wanted to mention a few aspects of planning and how to get transmission built. Maybe I can get at the question asked earlier, but I don't know that I am going to have a satisfactory answer for it.

I want to talk about appropriate planning, project finality, regulatory certainty and certainty of transmission rights.

Appropriate planning. I just want to take a step aside and talk about one planning process that worked.

That was a process that we went through when we were merging with Southwestern Public Service Company.

And in order to process that merger, we agreed to plan and to build a transmission path from our system in the panhandle of Texas to Colorado.

In order to do that pursuant to the FERC's merger order, we entered into a broad public participation process several years ago.

And we undertook an invitation to numerous parties, I think over 50 entities participated in that.

And in developing that we involved people from New Mexico, Texas, Kansas, Oklahoma and Colorado and put together a project.

I guess one aspect of this project was that it was designed to go from one place to another place, and we were able to accomplish that.

But -- and we are in the process of building that. It's one of the major interstate pipelines, not pipelines, transmission lines that are going to be interconnected with the eastern and western grids. We are excited about that with the HBDC converter.

But that brings up another point. Normally, when we talk about regional planning, people would not consider Kansas and Colorado and Texas to be in the same regional planning area.

I still don't.

In fact, I asked some folks from Kansas the other week about it and asked them if they believed that we are in the same region. For basic planning purposes we are not.

However, now we are going to have this interconnection, and there are suppliers in Kansas and in the eastern grid that want access to this market. So, for better or worse, they are part of the planning process.

Recently I have had another conversation with folks from Wyoming that are talking about developing another subregional planning group, that that group would involve Wyoming, Colorado and Utah.

When we met with them and asked them about this, we said, well, why doesn't New Mexico, Arizona, why aren't they also included in this?

And they said, well, they might be, but they are not at this point.

That raises the issue of the appropriate planning subregions, because everything that you have heard here so far didn't involve Kansas.

But in terms of our resource supply, it does involve access to the eastern grid.

So trying to look at the appropriate planning region is very important. Then having a correspondence between those planning regions and the RTOs that are developing, because as we look forward to a plan, we need this correspondence. That is where SSG-WI comes in in trying to align these planning functions.

In Colorado, for example, and other western states we still have integrated resource planning. We go through a planning cycle and resource acquisition every four years here through a bidding process and things like that.

There is not a way yet to integrate the resource planning cycle and subregional planning and transmission planning. And we need to get at that.

After a project is approved and our transmission line is an example of that, we have -- we want project finality.

The planning cycle for electric transmission is a lot longer than it is for electric generation, if you can believe it.

So by the time you go through the planning cycle for the need for electric transmission, establish that need, routing and get through all that, by that time the structure, the nature of the market can change.

We have faced that because there are people who want to get access to that transmission and there is a tendency to stay stop the music, let's revisit this thing. If that happens, we will never get anything built. But that is happening. So project finality is important.

Another aspect is regulatory certainty. When we went forward to develop a certificate of convenience and necessity and the need for signing this, an interstate line, we needed to get state certificate authority to do that and approval to recover those costs.

We found ourselves in one of our projects in a position of double jeopardy. And that is, our states looked at the need of the state, and there are -- state commissioners are elected or appointed to protect the interest of those states. That is fundamentally what they are charged to look at.

So in looking at cost recover recovery, there can be slippage of costs falling through the cracks, that can happen between states, and I believe can happen at the federal level as well.

Then the certainty of transmission lines. When I'm talking about resource planning, doing it through the perspective of a state utility, regulated utility, integrated utility, and we want to get the transmission rights to serve our load, that is what the expectation is and what we would plan to do. But the assignment of the transmission rights, and as we look at the standard market design, is obviously an open issue.

Those are the primary things I wanted to talk about today. Thank you for the opportunity.

MR. MILES: Thank you very much.

Any questions, because we are behind schedule.

If there aren't any questions or comments, then why don't we thank the panel for their presentation.

(Applause).

MR. MILES: Next and last panel is an opportunity for state, federal, tribal and international representatives to get together and talk about some of the comments they heard or want to share some observations with each other.

For those of you that would like to participate, please join us up in the front. If you do, bring your tent, if you have one. We will get started in about another five minutes.

(Recess.)

MR. MILES: Thanks.

What we have done at the other infrastructure meetings is close it with a dialogue of the conversation among the state, federal, tribal and international representatives to see if they have additional remarks they would like to add to this conference. So to have them engage each other.

With that, would anybody like to start off?

Roger?

MR. FRAGUA: First, Richard, I would like to thank you for running around with your head cut off keeping the conference on time. I appreciate that.

Chairman Wood, Commissioner Brownell, thank you for the invitation to address the Commission and audience on this very important conference.

I'm Roger Fragua, deputy director of the

Council on Tribes, 54 federally recognized tribes of council since 1975. We network with about 250 other tribes through an ad hoc organization called the enter tribal energy network. We have been working at energy projects and policy since about 1975.

I was commenting to my compadres here from New Mexico, this conference is like drinking out of a fire hydrant - there is so much information coming at you pretty quick.

But we are more than happy and pleased to participate.

As I understood the topic for this particular session was to discuss potential conclusions and next steps, where do we go from here.

We would like to offer from the council of resource tribes, serve along with FERC as a contact with FERC policy statements to implement and strengthen the government relationship with federally recognized tribes.

There is a little bit of a different twist in working with tribes as they are sovereign nations. Navigating and organizing a tribal perspective is hard for us to do, and we have been at it since 1975 and our board is comprised of tribes.

But we would offer that to the Commission formally to assist you in implementing your government to government policies, to help strengthen the government to government relationship.

Also to invite you to, there are a couple fliers floating around to the Indian Energy Solutions Conference, thank you very much, to participate, to meet with tribal leadership in their conference to discuss potential project and policy development opportunities.

So that in a nutshell is really what I would like to do in terms of introducing the council of resource tribes.

Membership is, again, comprised of 54 tribes which makes up 3 percent of the tribal populations that are growing about 3 percent of the national average.

With the influx of so many gaming dollars, there is increase in tribal economies. That essentially is our organization. We are able to do this through networking with tribal leadership, White House, Interior, Agriculture and Energy.

So we stand ready to partner with the FERC on future activities.

Thank you.

MR. MILES: Thank you.

Chairman Ellenbecker, any comments?

CHAIRMAN ELLENBECKER: Steve Ellenbecker, from the Wyoming commission.

I think the pause in the crisis, if there is one, actually is the best opportunity to perfect the markets, not only its infrastructure but market rules.

So I want to applaud the FERC, even though you have perhaps, with some patience that was due, given the west an opportunity to become more directly involved with you in working on the market structure.

I think, in fact, it's right for you to continue to pursue your project, the overreaching project, to try and perfect the infrastructure, not only electric as it relates to the RTO initiatives, but as it relates to what I see as a more rapid certification of interstate pipelines as well.

I think we have a deserving public out

there that deserves reasonably stable prices that are affected by moderate movements in supply and demand rather than crisis proportions that we have failed to figure out the way to properly manage through congress and through states and through perhaps the FERC as well.

I think it's right to continue in view of that and in view of all the competitive resources that were mentioned today, available to the customer, that have to get through this connective tissue, the ligaments and tendons and pipelines and interstate transmission lines to get to those customers, I think we ought to focus our attention on good public policy that treats a unit of energy as Chuck Goldman might say, saved of near equivalent or equivalent value as a unit of energy consumed, that treats wind and coal and natural gas compatibly and makes the connective tissue or the infrastructure one that they can expect to have access to on a basis that accommodates them, that treats them fairly, that doesn't discriminate among resources.

I think congress ought to focus its attention on diversification of these resources with environmental concern accompanied by state environmental considerations. And I think a state, like Wyoming, is showing good public interest consideration in its promotion of continued clean coal and coal bed methane and other natural gas development in an environmentally conscious way.

I think that there is an opportunity here that we can lose if we don't partner with each other as federal and state and international and western regulators on both sides of the borders to believe that there are ways to improve the market infrastructure in a way to better serve the public and better promote the development of resources in a manner that can reach the customers.

I think that market participants deserve clearer rules. I think they deserve more transparency and better assurance of compensation of what rules apply to whom. And I think the rules ought to be regulated and applied equally to all to promote utilization in a fair manner of much more diversified mix of resources.

And I actually think that is compatible with what you have been trying to do. So I might take a different twist and applaud the initiative.

I would actually hope you continue your initiatives to create these infrastructures that can work commonly for resources in a fair manner to any competitor.

In the end, the technology was so strong that, with or without us, those technologies will find ways to customers. It's our responsibility to ensure that they can find and reach customers in the most efficient manner and most economical manner possible.

I actually think that's what you have been trying to do, and I think it's incumbent upon the state regulators to support that initiative in a way that is modeled best for the west.

MR. MILES: Thank you.

Bill Bingham.

MR. BINGHAM: Thank you. Just a couple comments from my perspective.

Normally we sit a couple thousand miles north of here. It was interesting, the discussion. I was remarking how the climate has changed with respect to Canada.

I can remember not too long ago sitting in conferences such as this, talking about markets, 2010, and, by the way, Canadian gas will fill the gap, there is so much of that, we were counting on that.

A year ago there was a conference and there was talk about this market again. But we are not so sure about Canadian gas anymore because we have those oil sands projects up there in northern Alberta. I think, Mr. Chairman, you were there earlier this year.

Then there was talk about, well, you are going to have the gas, we can get the oil but we can't get both.

Today, similar comments I have heard recently is there is a big question mark with respect to Canadian gas.

I think there is a good reason why. We are seeing the same things that you folks are as well. It's production from the basin seems to be maturing.

We are going to have to see a real effort in terms of getting some of the unaccessible areas, more rugged areas in northern BC to exploit the large resource base there.

My personal view is there is still room for an uptick in supplies. We won't see the supplies we saw, but there is certainly a market for that gas.

I'm particularly optimistic about some of the other resource areas in Canada. We talked of the north earlier, but even the east coast, there is promise in that area.

We had disappointing results recently with some wells. But I will tell you what, the last couple days in the streets of Calgary there is talk about potential discovery we just came across (inaudible) and its Tcf.

If that in fact is the case, that will make it possible to develop that field which they hope to produce at the rate of four hundred million a day.

What I see going forward is perhaps a shift in regional flows. Perhaps with growth on the southeast coast we will see more exports to the United States, particularly New England and northeast markets. That may allow western supplies to stay closer to home and continue to meet the needs of Canada and also into the western U.S. markets for a longer period of time.

One other remark I would like to make is to congratulate the Commission on this forum.

I'd also -- I've seen the number of state Commissioner today and also would impress upon you folks, it would be nice to see you in Canada sometime, delegations from the energy council and interstate gas compact commission, and I think these dialogues are helpful for everyone and to avoid what we sometimes call North American blind spots, assuming the wrong things with respect to each other.

Again, I congratulate you.

MR. MILES: Thank you, Bill.

Francisco, any comments?

MR. De la ISLA: Only a few words.

I think that what is worth learning here from our perspective is that the frontier of endless resources is -- does not exist anymore. I think we are coming to a point, or realize at least in Mexico that we need to (inaudible) very quickly.

And because we cannot respond immediately to current conditions in the market, growth and demand, we are looking outwards to find solutions.

I would like to think that what may be the LNG does offer a hand in this problem. And that, increasingly, the world will become a global gas market, more like the oil is right now. And that we will be viewing it not only as an aid, but as an integral part of our system.

Something important I think we have to consider is that in order to help it grow and be of strategic importance, we need not to create barriers of entry, whatever they may be.

That is the remarks I would make. Thank you.

MR. MILES: Thank you.

Commissioner Smith.

COMMISSIONER SMITH: Thank you. Marcia Smith, Idaho Public Utilities Commission.

I want to thank you, Mr. Chairman, and Commissioner Brownell for this review. I think it's been helpful for me to review today's status and tomorrow's needs.

But I have to say, you know, I have been here since Saturday. And between the natural gas panels and the environmental panels that we had, I have got to say I'm scared.

So today's analysis was a little helpful in that there were actually positive things said and some signs of improvement in action that might be helpful in the future.

With regard to that, I think there were three things that, as (inaudible) these are all the issues we deal with on a regular basis.

With regard to transmission planning, I think we are very hopeful with the subregional planning efforts of the SSG-WI, but they are not without concerns.

A couple of the main concerns interested by CREPCI members are that public policy consideration needs to be in the mix of what the SSG-WI process is.

I think it's no surprise to (inaudible) I'm sure you have said that before, and that non-transmission solutions must have equal consideration with the idea of just building new wires.

So I think they are well aware of our concerns, and we are working together with that.

With regard to resource adequacy, CREPCI has a new team, have you heard of the WRATS? And don't forget the W.

But they have been very helpful and successful in making significant improvements in the WEEC's resource assessments reports put out periodically and definitely will continue in that effort.

We are very excited about those improvements which I think will help us to have a better picture of what our resource picture really is in the west.

Frankly, although it may not be exactly on point for today's seminar, I just want to report that with regard to market monitoring, we have been working hard with your O and Y office, we are pleased to report that they and a number of states have entered into an agreement of shared understanding, actions we are going to take, the goal from the stateside I think is we want a west-wide market monitoring, we want it to be independent, and we don't want to wait for RTOs, we want to get started now and have something that functions to help both the federal agency and state agencies do their jobs.

Thank you.

MR. MILES: Thank you, Commissioner Smith.

CHAIRMAN WOOD: While we are transitioning, I wanted to recognize two representatives from congressional members offices, Scott Prestich from Congressman Udal hear in Colorado. He stepped out.

Also, Dan Skopic from Congressman (inaudible) in California. We want to thank you all for being here. You might sit up at the table and visit with the rest of the folks.

COMMISSIONER ROWE: Bob Rowe, from the Montana commission. If we have WRATS, Marcia, is their a Pied Piper? That is a good thing.

Steve talked about pause in the crisis and there was something of that tone today, that was comforting.

In Montana, in fact, the perception is the opposite. There is more public fear, apprehension and awareness of what is considered by the public to be an energy crisis both on the gas and electric side than in quite sometime.

Quickly, a couple specific Montana concerns. As you know, we are a substantial net exporter. We have significant potential for both traditional, renewable resources.

There is also real concern about the potential for local market power, much of which is driven by transmission issues described in a July 25th filing by the Independent Consumer Council. I won't restate that, but I think it's an important document.

So we, I am concerned that there be the opportunity for economically efficient transactions and projects, both to sell into and to sell out of Montana. Much of the conference today I think spoke to those concerns.

A couple of random points. I have substantial concern on the out years, a range of possible scenarios. We saw that.

And I want to particularly note the Canadian use of formal scenario planning. That is a very good complement to IRP and other strategies.

Something we should be looking at. A lot of uncertainty, a lot of risks associated with that uncertainty.

Much of what we have to do is develop strategies to identify and minimize those risks.

Strong concern about a whole variety of problems, finalities, border issues, jurisdictional externalities, financial externalities. The discussion of transmission was entirely on point as to both those topics.

I did appreciate the discussion of both the demand side and demand response issues. The

Power Planning Council work, ongoing work on a regional plan is very, very helpful there. They are moving to recognition that on the demand side, programs can't really be ramped up and ramped down, but need to be sustained. Those are important both on the gas and electric side.

I have a long-standing concern that the, particularly on the generation side, there was an overly high tolerance for fuel price risk in order to avoid capital risk. And I think conditions in the last few months have borne out that concern.

One partial solution or way to address at retail some of this risk, I will commend the Montana example as something good happening. We all know the rest of the west has remained vertically integrated, while we have opted for a model of dis-integration. Pun partially intended.

A couple of tools in Montana. We have developed some very good portfolio guidelines, IRP Light, much more flexible, but I do try to minimize much of the risk.

It also developed what I think is a more focused, efficient and less risk shifting approach to what we are calling advance approval, the Electric Committee discussed some of those yesterday.

There is some good process behind that, as well.

Finally I want to commend you, obviously, for being here. Also I thought the wholesale market platform white paper and option paper that followed on were very good, very flexible tools and responded in my mind to a whole series of issues that were raised in the west and elsewhere about standard market design as announced last year.

Those are -- those create a wonderful opportunity in my mind to build on the specific things Marcia described, I think, to alert of some things happening out in the midwest as well, and to really strengthen the effort at regional cooperation to deal with all the concerns we have been discussing.

The one piece I would like to really move more up to the information front is the idea of western structure that was developed initially, I think, through the western governors association process and move much more explicitly toward what

I felt the cooperative federalist approach, also what has been called a western market design, which is the best use of the initials WMB I can think of.

Thank you.

MR. MILES: Thank you, Mr. Chairman.

COMMISSIONER HEMSTEAD: I'm Dick Hemstead, from the Washington commission.

First, some comments from the panelists with regard to regulatory certainty.

I realize there has been a considerable amount of turmoil in the last couple of years in the markets and among regulators.

But I want to emphasize, and I think this is a reasonably accurate statement for substantially all of the western commissions, I think the western state commissions are working very hard to provide reasonable regulatory certainty and predictability for the utilities we regulate to see that they have the opportunity to make adequate returns, that they get cost recovery, that we are all moving to more risk sharing among the utilities and their ratepayers and to see that their market ratings are upgraded after all of the significant turmoil so that they can go to the market and raise the funds that they need.

I'm confident that is the case with the utilities that we regulate, and they will be able to go to the market and borrow money at reasonable rates to build the resources or buy the resources that they need.

But beyond that, a couple points I would like to make.

There is a renewed and strong I think deep emphasis on regional planning within the west. And I say this now specifically in the context of western regulators as they interface with the oil -- all of the other things going on.

We have power planning, we have transmission planning, we have facility siting and dealing with enhancing the ability to new transmission placement.

And we have transmission power and market monitoring.

All of these things are under way in ways that they haven't been in the past, and I think progressively will come together in a way that is going to work well.

When, some years ago, when I first became a regulator, I recall a hearing, I recall hearing one of the economists saying that integrated resource planning was, by individual utilities, dealing with their utility commissions, was not only a waste of time, but it was counterproductive, because it was antithetic to the markets because the markets were going to answer all those questions.

Well, I'm here to tell you that there is renewed strong emphasis among the commissions, at least in our commission, and I know elsewhere, with the utilities we regulate, we expect them to plan on short-term, medium-term and a long-term basis as to how they are going to -- what kind of portfolio management they are going to pursue and where they are going to get their resources and pulling in the demand side management as well as new supply.

And it is working, I think, remarkably well. And it simply fortifies and emphasizes our renewed focus upon planning in the west.

So in translation, it seems to me what that means is for decision makers or regulators, is, well, on the one hand we have to think regionally, we still are statutorily and legally obligated to act locally. But it has to be within the context and the perspective that regional planning provides.

And so the mantra is, think regionally and act locally, and using the tools of both regulation and competition, not as alternatives, but as tools that can be used in tandem to achieve the results of reasonable -- reasonably priced services and reliable service.

MR. MILES: Thank you.

Mr. Chairman.

COMMISSIONER SOPKIN: I know it's past the 6 o'clock hour, so I'll be very brief.

First off, it appears there may well be a mole in the natural gas crisis. But I still think it's appropriate to use the word "crisis" if crisis is defined as a serious problem that needs to be dealt with quickly.

We had an expert here a couple days back that was quite alarmed to have $4.70 in August. That is unheard of. And he was not very optimistic for what the winter heating prices were going to be.

There was an article in a local newspaper here a couple days ago saying that good news, rates won't go up this winter or may not go up this winter.

But what was not said is rates went up substantially in the spring and people don't use a lot of gas over the summer months, so they are not going to find out until the winter that their heating bills are, in fact, going up substantially this winter.

In my mind, the only short-term solution to this problem are number one, mild weather, my jurisdiction doesn't extend that far and, respectfully, I don't believe the FERC's does, either.

Or increased domestic supply. I fully realize I'm talking to the wrong agency here, but the federal government needs to do everything it can to try to deal with the situation.

I guess I'm primarily talking about the Department of Interior as far as expediting the permitting process and determining reasonable compromise between environmental interests and what is an issue that affects everybody in terms of much higher heating bills.

And it has affected the economy in this country. Industrial jobs have been lost. And the real long-term situation does appear to be LNG solution.

The mature market, I believe gas prices will not be nearly as volatile as they have been.

So again, the federal government needs to encourage companies to build LNG degasification terminals.

Since I don't have a lot of time, I just wanted to mention, Colorado, at least, speaking just for myself, I'm not sure it makes sense for Colorado to be forced to join an RTO.

The number one objection that I have to the process is this regional state committee process that has been outlined which does not appear to be accountable to shareholders , any public utility commission or ratepayers. It just exists out there.

And there is no structure to deal with the situation that undoubtedly will occur, which is when states disagree with each other about things.

And in particular, I think the issue of participant funding is going to come up between states. There's going to be very different viewpoints on that issue.

So it makes for a very long discussion so I'll just leave it at that. At this point at least, I'm not prepared to concede the issues of regional generation, transmission, transmission rates, energy efficiency and demand response to a regional state committee.

Thank you.

MR. MILES: Anything additional?

COMMISSIONER KING: Thank you.

David King, from New Mexico. I appreciate being here. We appreciate the opportunity to speak.

As a new Commissioner in New Mexico, I think about acting globally. We are probably the number one exporting state in the western region. We have tremendous gas reserves, much more than I think has been credited today.

In looking at that I think we have to declare an emergency in the transmission area, whether we are talking about electric, gas, I think the RTO has some opportunity for us we have to look at carefully.

There are tremendous areas we have to look at carefully locally as we look at the tremendous Indian lands and transmission leases that are expiring coming up dramatically. I don't think it's been looked at carefully enough.

Much of this transmission, we are talking about all these states in the west, have got to work carefully there.

I think there are some new opportunities there, but a means of dialogue has to be established, and we have to look carefully. I think that is important when I look at the energy areas that we have and sending it out, 25, 30 times as much as we use easily, there are opportunities there, but we have to look at them locally for those native American areas and some of the rural areas for development that we have not had, because decisions were made years ago.

So I applaud the efforts. I think it takes a lot of communication. I think we have to have some hearings in our state, going to be doing that, the legislature has mandated some hearings around the state to look at what it means to us as we look at the different federal initiatives.

So we are having hearings all over the state through our state commission. We would like to work with you all to be sure you are invited to that and that we create a dialogue there.

I think it does have to be a partnership. I think there is much that can be done.

I have a lot of confidence. We have a lot more resources and we are not going to be exporting for a long time if we do some things right in the transmission area.

I appreciate this opportunity to dialogue and visit with you.

CHAIRMAN WOOD: Thank you.

MR. MILES: Thank you.

Any additional comments or observations? Are we at an end?

CHAIRMAN WOOD: Are we? Anybody else? Just because you are in the second row doesn't mean you can't talk.

Anybody in the audience want to contribute anything? We have got a mic stand back there, if you like. Just kind of wrap up thoughts for today. New items to throw out into the air.

All right. We are a little overtime. I want to say I appreciate the participation of some great speakers, our colleagues here from the states, our folks in our other nations in the

Indian tribes with our North American neighbors, Mexico, Canada.

Really appreciate you all coming, because which are not only at a state level but national level, we are not an island and we are not an electrical island, no state is.

Maybe one.

(Laughter.)

CHAIRMAN WOOD: We are not a gas island for sure. I think we are one great big global pond there.

I think we have had nice perspective on the LNG issues which are certainly a lot of things we have heard about in recent months.

But the whole totality of resources, I, with Mr. Ellenbecker, yesterday, toured the largest coal mine in North America and looking at that resource, and that is something we at FERC don't have that much of an opportunity to look at directly, because we don't have a regulatory role there.

But the plethora of resources out here in the west is quite abundant, and I think the good stewardship of that is of interest to a lot of folks in this room.

I think a good understanding of interconnection is a good thing to do. I'm overwhelmed by the fire hose approach we had in the past, in the morning and afternoon.

But as Marcia indicated, it's been a long week already. Maybe we will try to do these as a separate event so we are all fresher.

We will have the transcript available in seven days. If people want to read it at a normal speed, it will be available on the web page.

There were great challenges I heard about. Clearly, infrastructure challenges don't go away. The point of the conferences is not to resolve a specific problem for tomorrow but to identify things that could be problems if we don't start working on them today.

So the people who have the ability to do something I think are in this room. Our collective attention and collective resolve to address these issues whether they are gas or electric, hydro, coal, environmental issues, supply and demand, regulatory governmental issues, there are a lot of issues here that tend to come up.

I think the more we get comfortable and familiar talking about them, that is really the purple of our convening these.

Planning, regional, subregional, this was clearly a thing we heard about. A lot on the electric side. Even some, too, on the gas side, which again has been more market driven than the electric.

I would like to call as an example the process that MISO, the group of 14 states that form an RTO just directly to the east of here, underwent, just in April of this year put forth after 18 months of study a relatively detailed plan of where the infrastructure needs TO BE upgraded electrically, with even suggestions about who the beneficiaries are so some fair form of cost allocation could be made.

I think one of the things I would urge for the west is to move from the planning and discussion phase to the execution phase.

I do think the memories of 2000 and 2001 are pretty current in my mind. But I know we are seeing a lot of new faces around here on the regulatory commissions and other places that may not have been here during that time period. And we need to basically learn from mistakes of the past.

I heard from the Transmission Planning Panel about the progress that has been made there and I just want to urge that that continue to develop and to produce detailed actionable projects that state commissions, state siting authorities can then take and move forward with and actually get implemented.

Certainly, I can't miss the opportunity to emphasize how important it is that clear and understandable rules and market transparency go forth.

Markets are easy to monitor when transparent. And it's easy to make sure customers are benefiting from the resource-to-resource competition and getting price signals for demand production, if there is a good market working and a good market in place.

So I would say that I am looking forward to following up on these issues, specifically the electric issue on the white paper conferences that are being planned for Phoenix in September and San Francisco in November.

Cost recovery issues are things we

certainly hear from all the utilities, and it's something I think we always as regulators are attentive to.

But I think it certainly should not go without remarking on today.

I want to say, Steve, your comment on technology is going to get to the customer. It's our job to make sure it's, without putting words in your mouth, efficient and effective getting there.

That's a new definition of our job description. And I really can't think of a better one, because you look at the last hundred years, technology has transformed the whole continent.

If we can play a role in making that day sooner and making it as pro-customer as it can be, I think that is a good thing you put on our epiteth when we go to the Great Beyond.

I want to thank particularly the speakers, again, members of the audience who lasted it out.

I want to thank in particular our staff, who have done a good job of setting up this conference here.

I do want to recognize from our colleague

Bill Massey, his smart brain trust.

I want to thank Carol Connors, who started organizing several months back, getting a nice set of speakers, including all the government officials.

Mark Robbins, director. Lisha Bond and Jeff Wright from the infrastructure group.

We do have a group dedicated to infrastructure. Jeff is head of that. Shavon is on that team, as well.

I also want to recognize John Carlson from the western region. He oversees all the filings that come in from the west.

Allison Silverstein of my office, and Cheryl McKinley from our shop.

Can't let it stop without the moderator supreme Rick Miles.

Have a good afternoon.

(Adjourned at 6:15 p.m.)